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Memorandum

From the office of
Commissioner Bob Burns
Arizona Corporation Commission
1200 W. WASHINGTON
PHOENIX, ARIZONA
(602) 542-3682

ORIGINAL

Arizona Corporation Commission
DOCKETED
AUG 19 2014
DOCKETED BY

TO: Docket Control

DATE: August 19, 2014

FROM: Commissioner Bob Burns

SUBJECT: Emerging Technologies in Energy, Docket No. E-00000J-13-0375

The agenda and presentations from the August 18, 2014 Emerging Technologies Response Workshop have been docketed. If for some reason you cannot access eDocket, please contact my Executive Aide, Jessica Perry, to receive copies of the presentations.

Original and thirteen (13) copies of
the agenda and presentations filed this 19th day of
August, 2014, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the memo mailed
this 19th day of August, 2014, to:

Service List

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DOCKET CONTROL

REVISED N O T I C E
SPECIAL OPEN MEETING
OF THE ARIZONA CORPORATION COMMISSION

Commission Workshop on Emerging Technologies
Docket No. E-00000J-13-0375

DATE: Monday, August 18, 2014 **START TIME: 9:00 a.m.**

Arizona Corporation Commission
Hearing Room One
1200 W. Washington Street
Phoenix, Arizona 85007

This shall serve as notice of a special open meeting of the Arizona Corporation Commission at the above location for consideration, discussion, and possible vote of the items on the following agenda and other matters related thereto. Please be advised that the Commissioners may use this open meeting to ask questions about the matters on the agenda; therefore, the parties to the matters to be discussed or their legal representatives are requested, though not required, to attend. The Commissioners may move to executive session, which will not be open to the public, for the purpose of legal advice pursuant to A.R.S. §§ 38-431.03.A.2, 3 and/or 4 on the matters noticed herein. The Commissioners may also move to executive session, which will not be open to the public, for other purposes specified in A.R.S. §§ 38-431.03, including discussions, consultations or considerations of Commission personnel and salary matters, on matters noticed herein.

The Arizona Corporation Commission does not discriminate on the basis of disability in admission to its public meetings. Persons with a disability may request a reasonable accommodation, such as a sign language interpreter, as well as request this document in an alternative format, by contacting Shaylin A. Bernal, phone number (602) 542-3931, E-mail sabernal@azcc.gov. Requests should be made as early as possible to allow time to arrange the accommodations.

Jodi Jerich
Executive Director

Agenda

Morning Session: 9:00 a.m.

Welcome & Opening Remarks

Presentations:

1. National Renewable Energy Laboratory
    a. Dr. Bryan Hannegan, Associate Laboratory Director of Energy Systems Integration
    "Presentation Title: TBA"

2. OASIS Energy Market Information Exchange Technical Committee and TeMix Inc.
    a. Ed Cazalet, Co-Chair and CEO
    "Transactive Energy: A Sustainable Business and Regulatory Model for Electricity"

3. GridWise Architecture Council
    a. Doug Houseman, Member
    "Transactive Energy: A Blend of Value and Control"

4. Southwestern Power Pool
    a. Carl Monroe, Executive Vice President and Chief Operating Office
    "Introduction to Southwest Power Pool and Energy Imbalance Market"

5. California Independent System Operator
    a. Mark Rothleder, Vice President of Market Quality and Renewable Integration
    b. Stacey Crowley, Director of Regional Affairs
    "Briefing on the Energy Imbalance Market"

6. Western Grid Group
    a. Amanda Ormond, Managing Director
    "Energy Imbalance Market- Customer Savings from a Modernized Grid"

Lunch

Afternoon Session

Presentations:

7. Residential Utilities Consumer Office
    a. Lon Huber, Special Project Advisor
    "Emerging Technologies in Arizona: The Projected Economics of an Energy Independent Community"

8. Itron
    a. Jeff Rowe, Western Region Account Executive
    "AMR vs. AMI and Smart Grid, the Benefits of Each for Arizona Utilities"

9. Elster
    a. George Lucas, Executive Director of Smart Grid
    "Presentation Title: TBA"

10. DNV GL- Energy Advisory
    a. Robert Wilhite, Managing Director, Americas Region
       "Emerging Technologies and Applications for Power Distribution Networks"

11. Salt River Project
    a. Aaron Dock, Manager of Load Research
       "Limited Income Customer EZ-3 Recruitment Pilot"

Wrap-Up & Closing Remarks

NREL

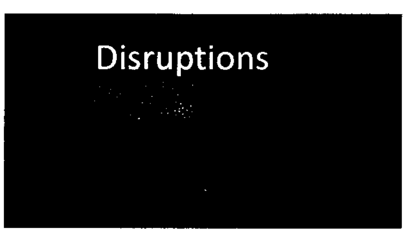
Energy Systems Integration

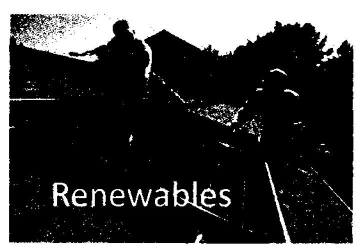
Dr. Bryan Hannegan
Associate Laboratory Director

August 2014

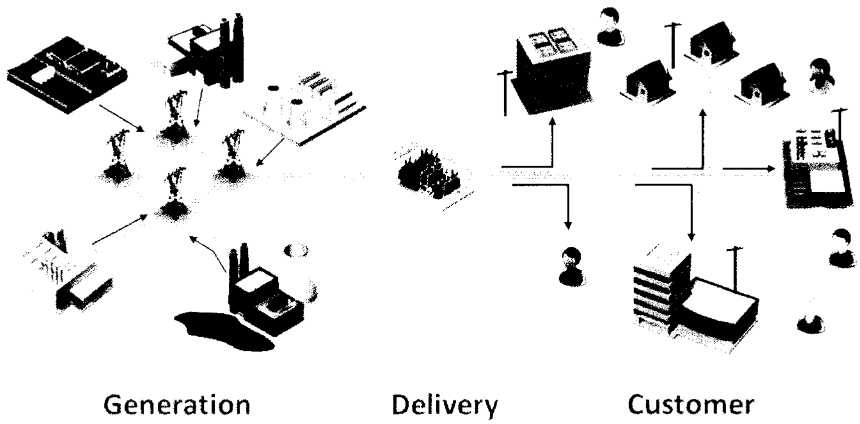
Why Energy Systems Integration?

Existing energy systems have served us well... but a clean energy future needs a modernized and integrated infrastructure.

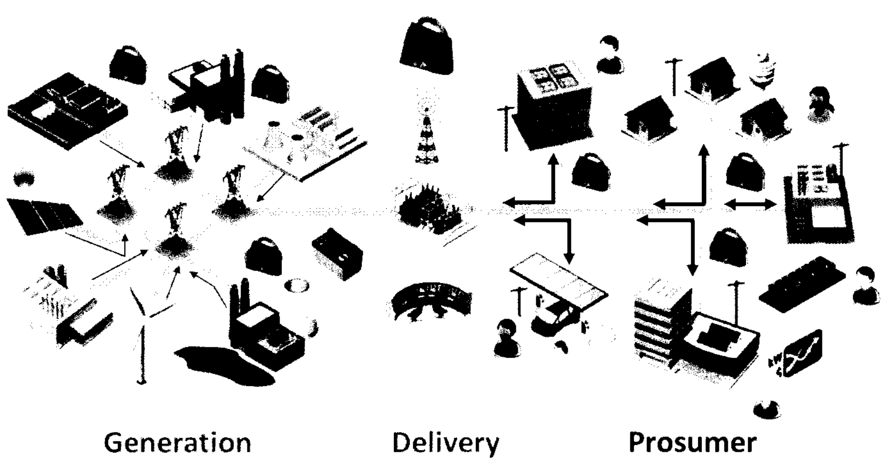




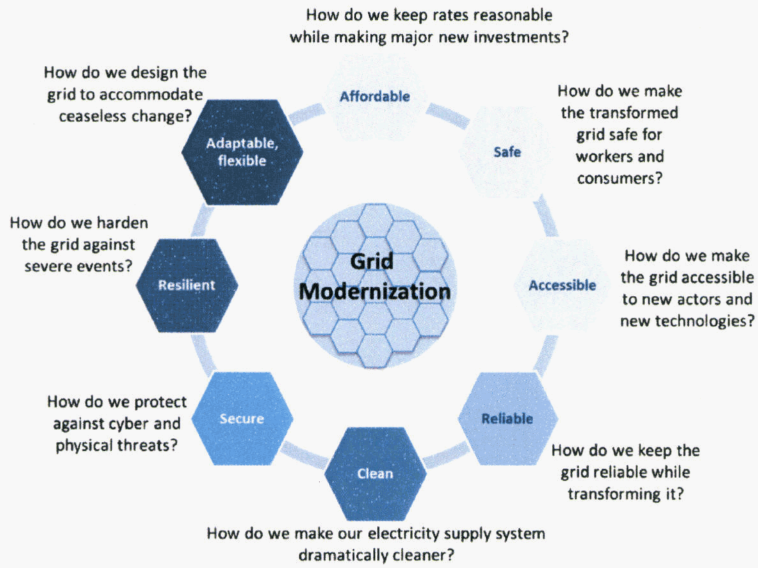
Today's Electricity Grid



Tomorrow's Power System



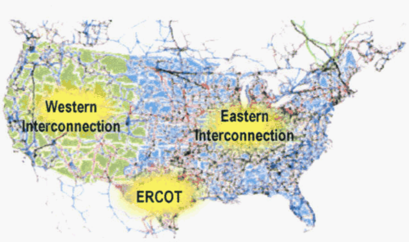
Key Grid Modernization Challenges



U.S. DOE Grid Modernization Initiative

System Control and Power Flow | Design and Planning Tools | Sensing and Measurements | Devices and Integrated System Testing

Institutional Support | Security and Emergency Response | Regional Partnerships

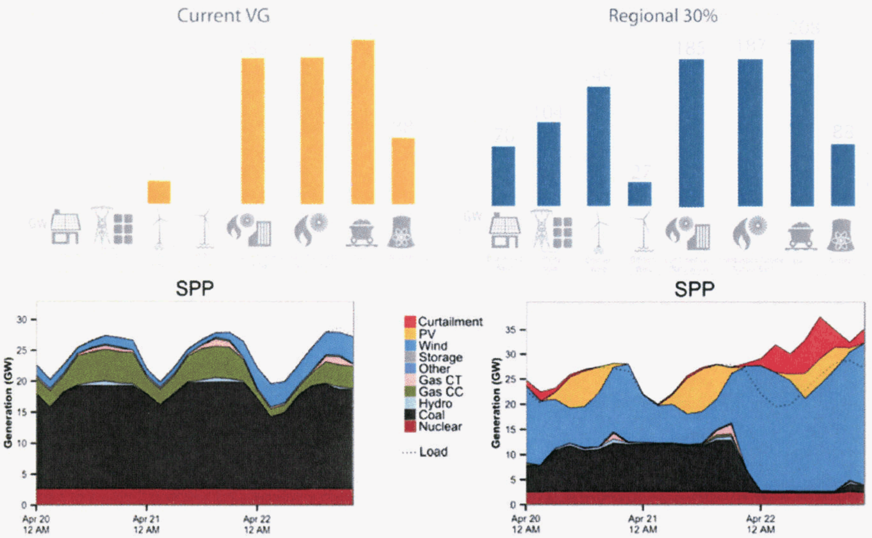


Challenges
- Aging infrastructure
- Increased asset stress
- Fuel mix changes
- Increase variability and uncertainty
- More information and potential control points

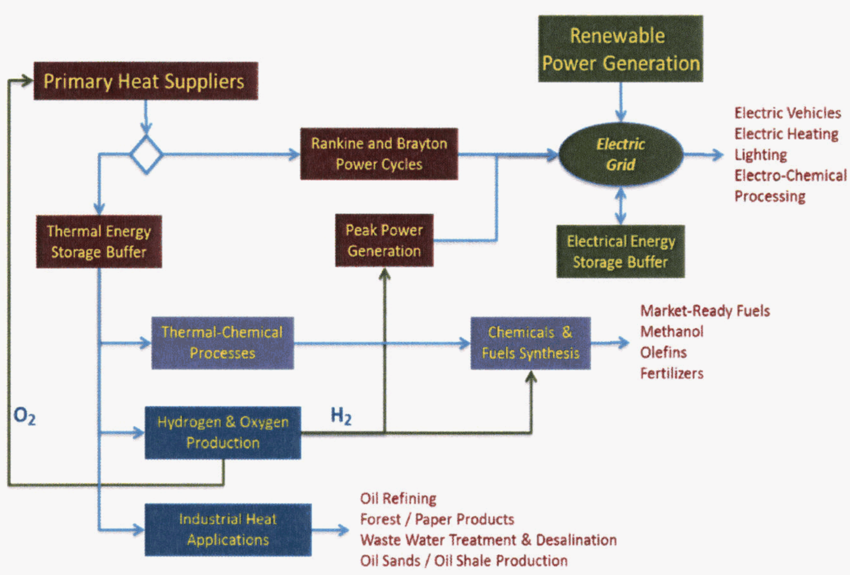
Goals
- Maintain reliability, safety, affordability
- Increase security and resilience
- Double installed renewables by 2020
- 80% clean electricity by 2035

A Look Into the Clean Energy Future?

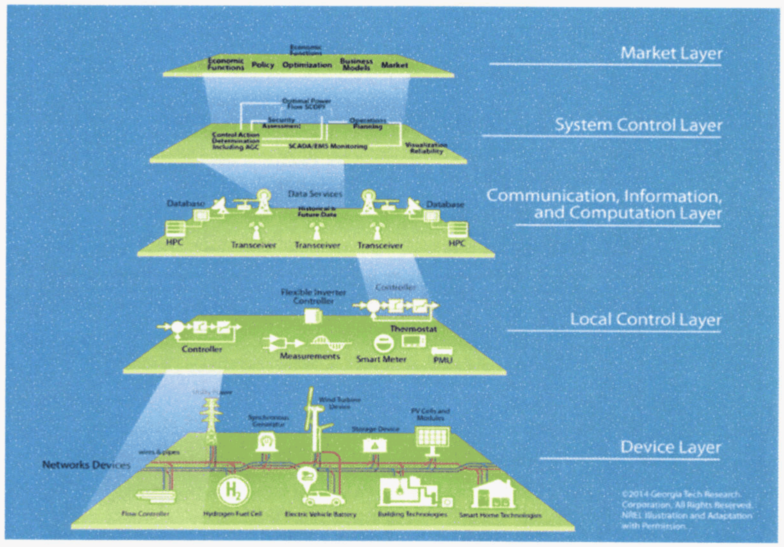
Eastern Renewable Generation Study (ERGIS), study forthcoming



Thinking "Beyond the Grid"



Future Energy System Architecture

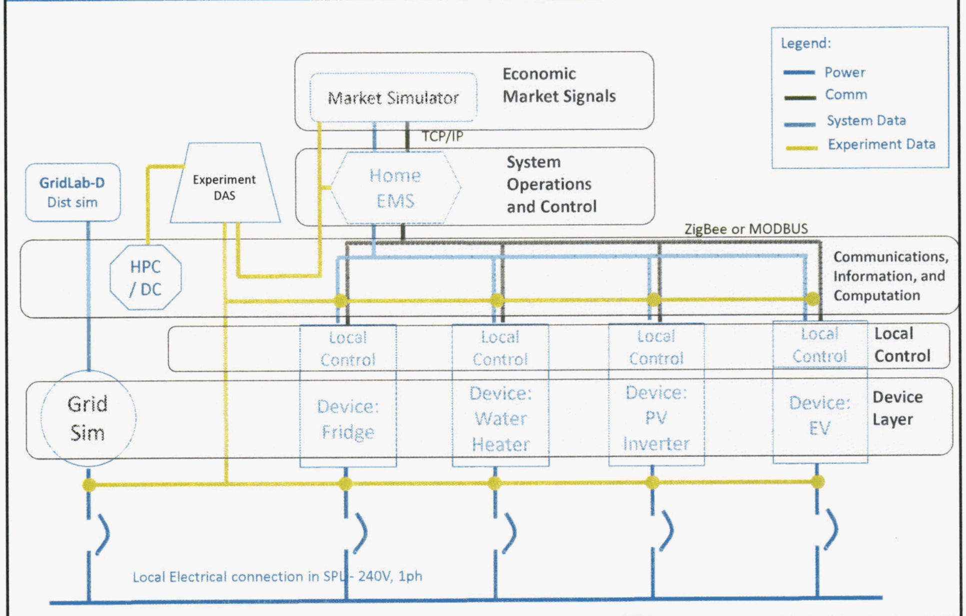


Energy Systems Integration Facility (ESIF)

- NREL's largest R&D facility (182,500 ft^2/20,000 m^2)
- Space for 200 NREL staff and research partners
- 15 state-of-the-art hardware laboratories
- Integrated megawatt-scale electrical, thermal and fuel infrastructure
- High performance computation and data analysis capabilities
- 2-D/3-D advanced visualization

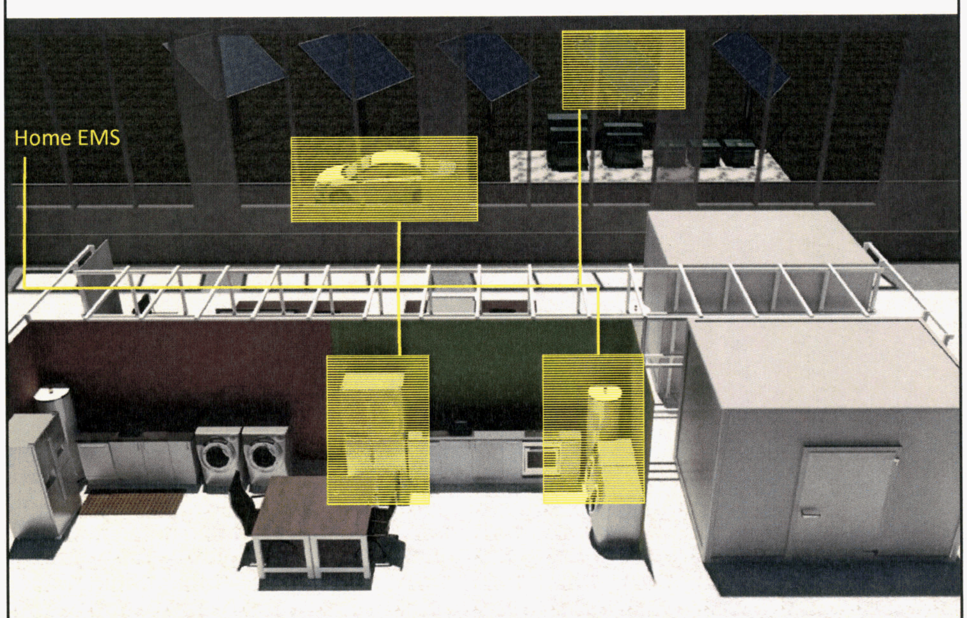
http://www.nrel.gov/esi/esif.html

"Smart Home" Example



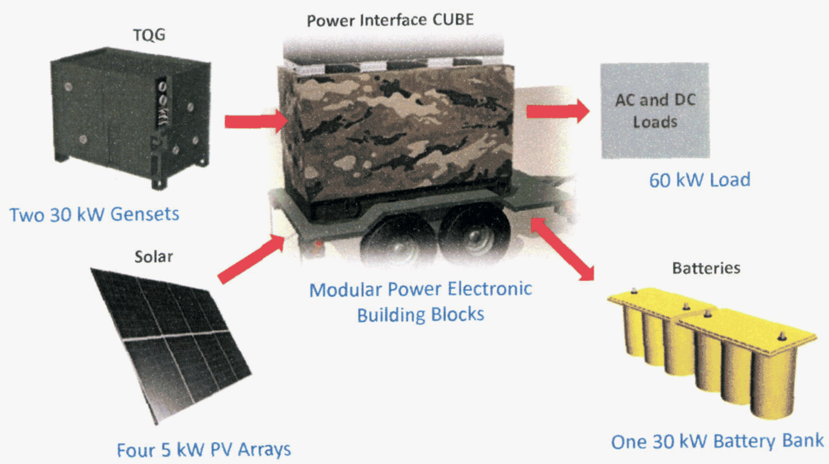
NATIONAL RENEWABLE ENERGY LABORATORY 11

ESIF Smart Power Lab

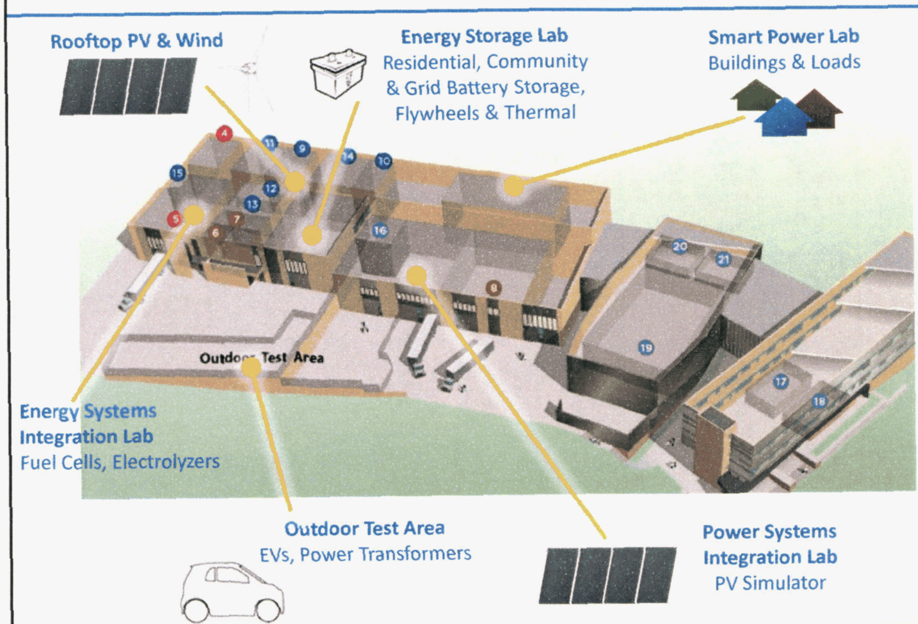


The "CUBE" – A Mobile Microgrid

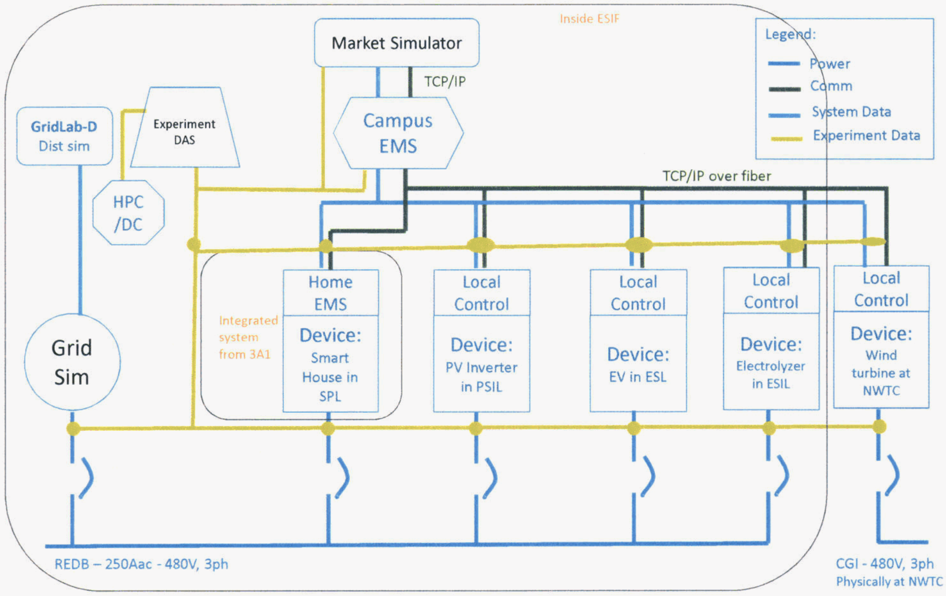
Integrated power electronic platform for 60 kW PV-Battery-Diesel hybrid power system developed for the U.S. Army



ESIF Laboratories



"Smart Campus" Example



iiESI International Institute for Energy Systems Integration

Addressing energy challenges through global collaboration www.iiESI.org

Vision

A global community of scholars and practitioners from leading institutes engaged in efforts to enable highly integrated, flexible, clean, and efficient energy systems

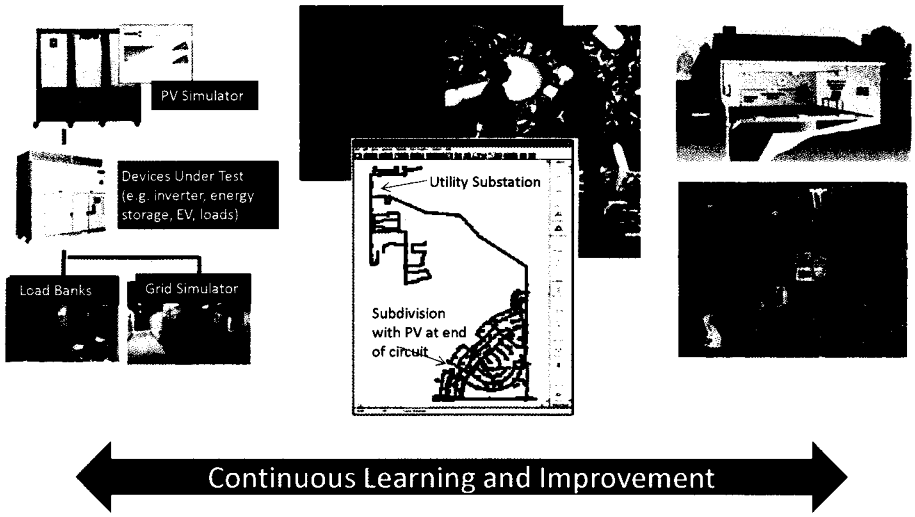
Objectives
- Share ESI knowledge and Experience
- Coordination of R&D activities
- Education and Training Resources

Activities
- Feb 18-19 Workshop (Washington DC)
- May 28-29 Workshop (Copenhagen)

NREL Pacific Northwest NATIONAL LABORATORY EPRI ELECTRIC POWER RESEARCH INSTITUTE UCD DUBLIN DTU KU LEUVEN

A Design Process for Clean Energy

Hardware Testing | Modeling & Simulation | Field Deployment



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For More Information

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http://www.nrel.gov/esi

Energy Systems Integration
Accelerating the Clean Energy Future

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Transactive Energy

A Sustainable Business and Regulatory Model for Electricity

Arizona Corporation Commission

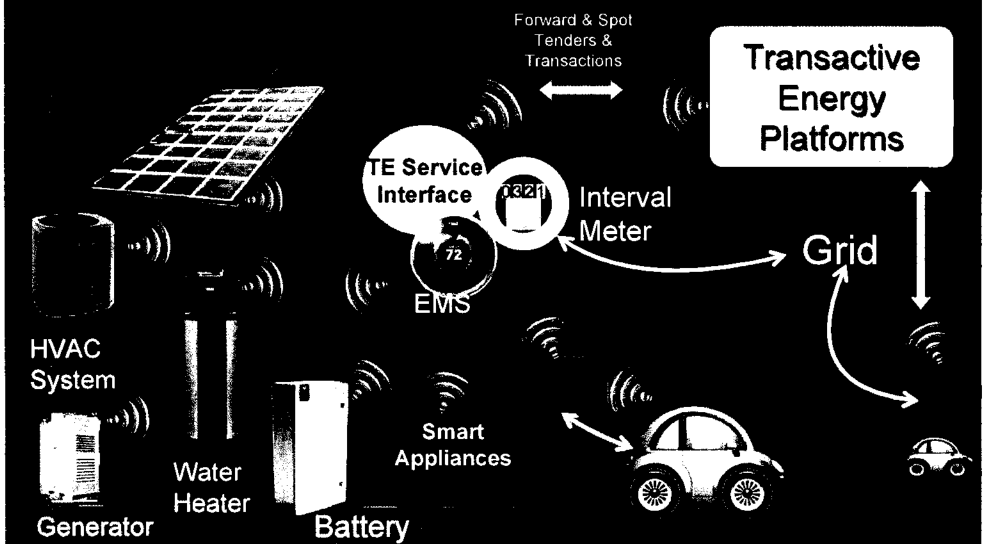
Workshop on Emerging Technologies
Docket No. E-00000J-13-0375
August 18, 2014

Edward G. Cazalet, Ph.D.
CEO, TeMix Inc.

Emerging Technology Issues

- Solar
- Interval Metering
- Advanced distribution grid control
- Communications
- Storage and Microgrids
- Arizona Duck Curve
- Retail rates and Net Metering
- EIM 5-minute markets

A building (or charge station) with a plug-in looks like this in the Transactive Energy (TE) model.



Here's an example of how TE works for a consumer.
(Interoperable Transactive Retail Tariff / Rate)

- Based on my typical usage, I automatically transact with one or more suppliers for delivery of a fixed quantity of energy in each hour of the year(s) for a fixed monthly payment (subscription.)
  - If I use less than I subscribed for in each hour then I am paid for the difference at an hourly spot price.
  - If I use more than I subscribed for then I pay for the difference at an hourly spot price.
- At any time I can automatically buy or sell a quantity of energy at current tendered prices.

My energy management system (EMS) automates this process

Transactive Energy (TE) has four big ideas.

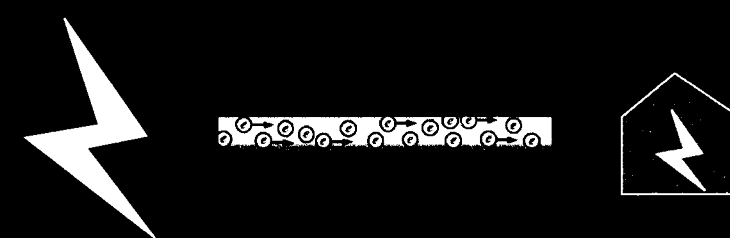
Forward transactions are used to coordinate investments and manage risk.

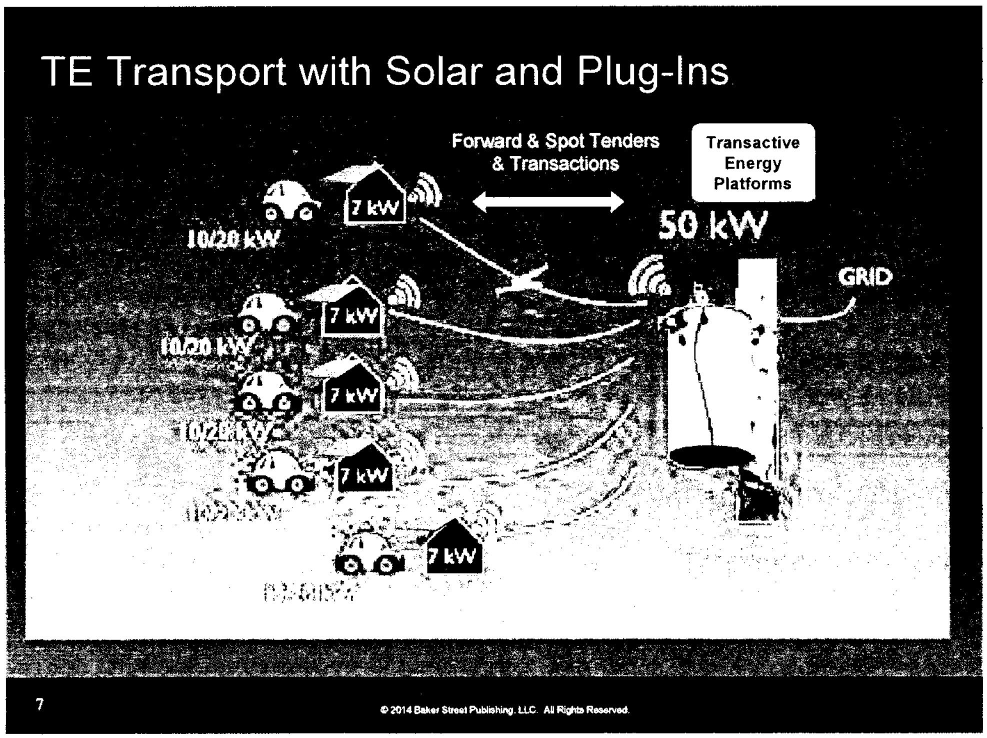
Spot transactions are used to coordinate operating decisions.

All parties act autonomously.

There are two products: energy and transport.

The two-way Transport product delivers the Energy product.




TE Transport with Solar and Plug-Ins
Forward & Spot Tenders & Transactions
Transactive Energy Platforms
50 kW
GRID
10/20 kW
7 kW
7 kW
7 kW
7 kW
7 kW
7
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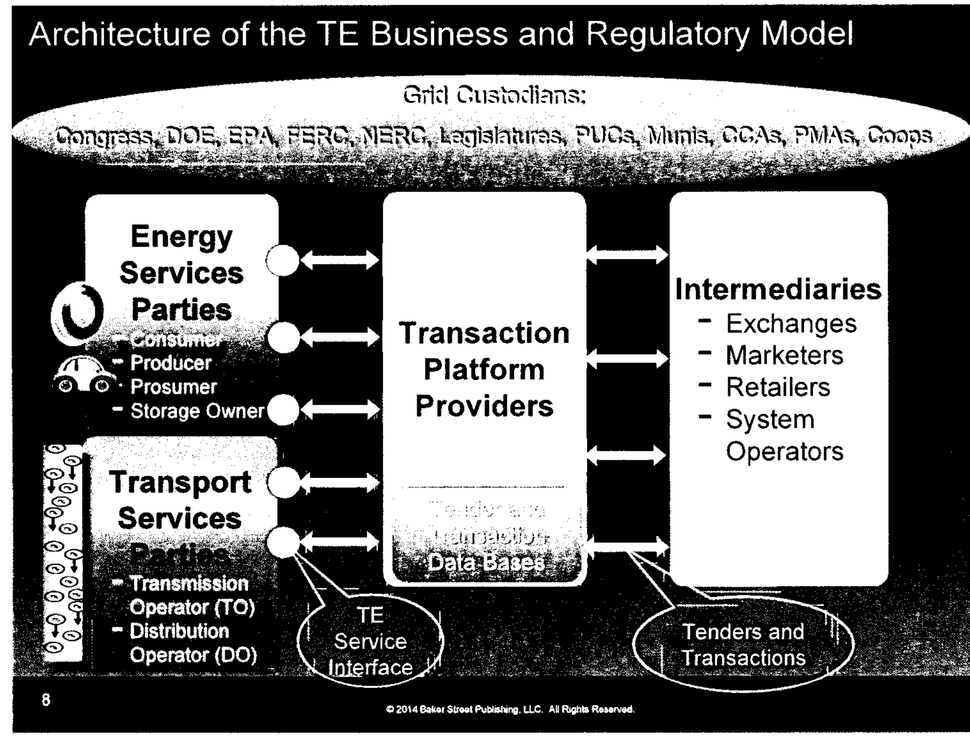
Architecture of the TE Business and Regulatory Model
Grid Custodians:
Congress, DOE, EPA, FERC, NERC, Legislatures, PUCs, Munis, CCAs, PMAs, Coops
Energy Services Parties
- Consumer
- Producer
- Prosumer
- Storage Owner
Transport Services Parties
- Transmission Operator (TO)
- Distribution Operator (DO)
Transaction Platform Providers
Data Bases
Intermediaries
- Exchanges
- Marketers
- Retailers
- System Operators
TE Service Interface
Tenders and Transactions
8
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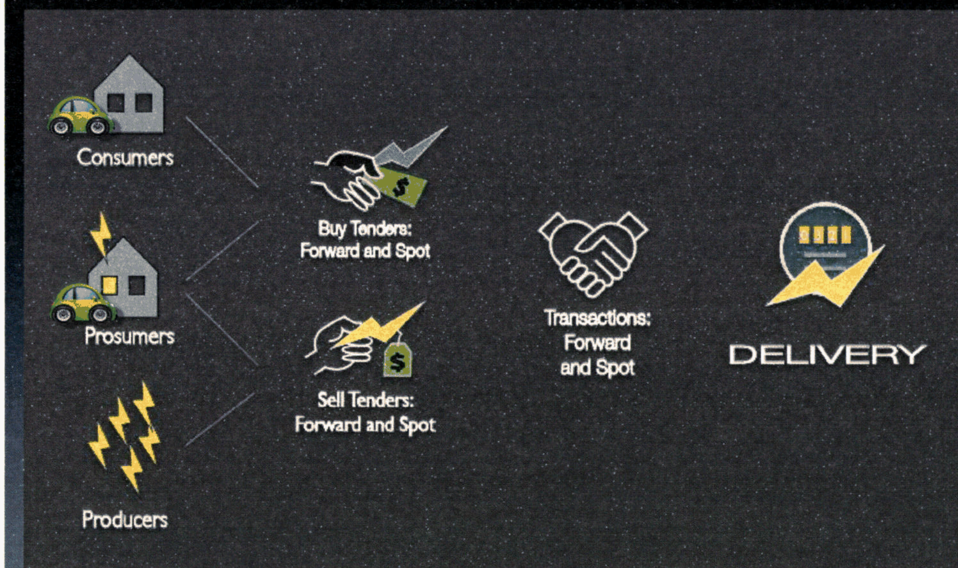
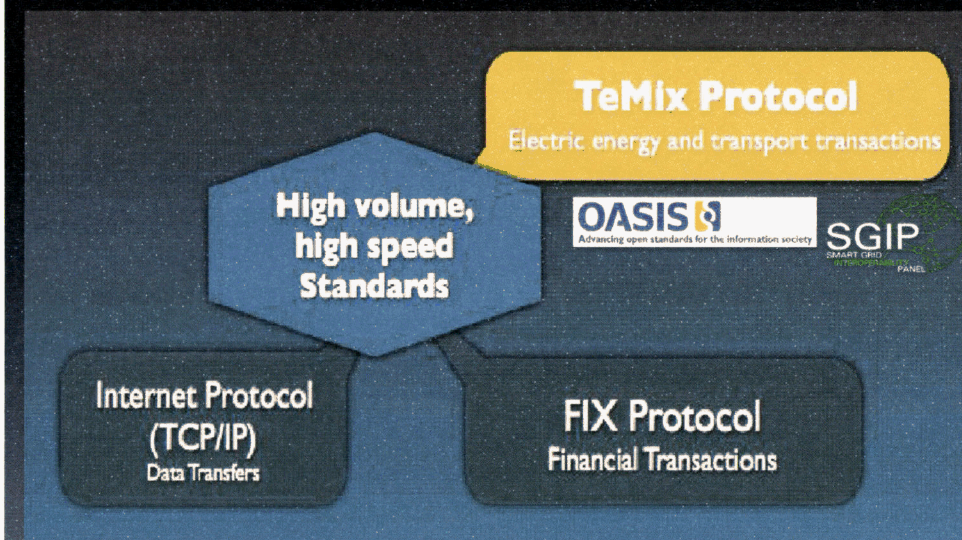
The TE business process is straightforward.



"Open and free" TeMix protocol supports standard transactions on multiple communications systems.



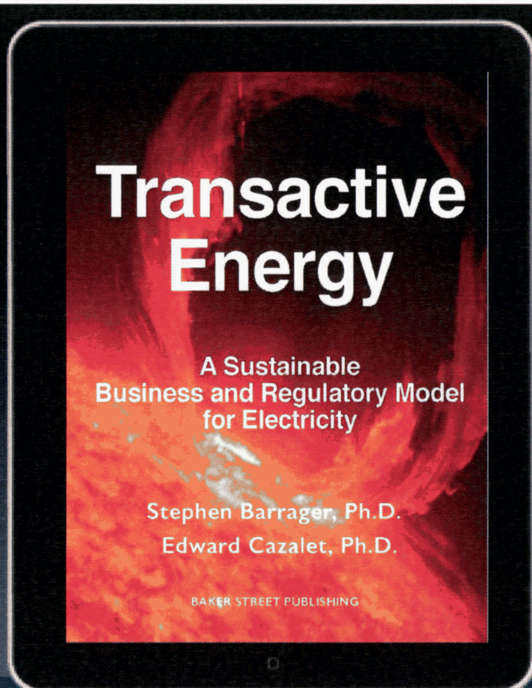
Transactive Energy can be incrementally deployed to work with current systems and entities.

Visit TEA for continuing open discussion of Transactive Energy.

TEA™

TRANSACTIVE ENERGY ASSOCIATION

www.tea-web.org



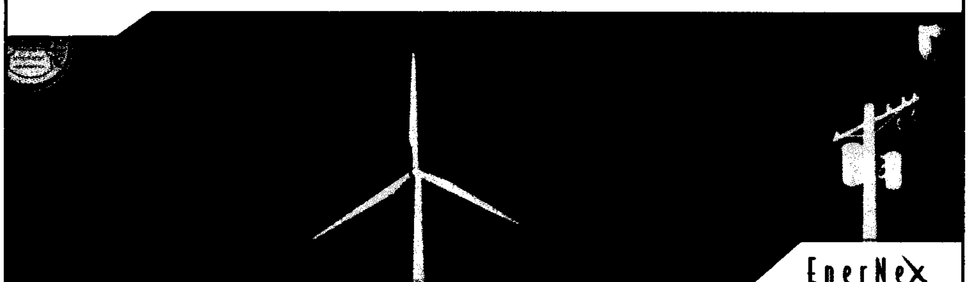
Available on the Apple iBook Store.

Key Takeaways to Support Emerging Technologies

- Operations and investment functions for energy and transport should be separate and coordinated using forward and spot transactions.
- Recover fixed and variable costs with
  - forward fixed priced subscriptions and variable spot prices on short intervals, <u>avoiding</u>
  - Minimum $/mon bill, fixed $/mon charge, demand $/kW charge and constant $/kWh charges.
- Distribution transport rates should be based on two-way flows on short intervals.

Transactive Energy

Doug Houseman
Doug@Enernex.com



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I Believe…

1. Distributed generation will become ubiquitous by 2050
2. That by 2030 roofing, windows, and siding will all have the ability to generate electricity on most new homes (the materials exist today)
3. That battery capacity (Kw/Kg) will improve at about the same rate that it has since the 1970s
4. 70% of the customers will not be able to leave the grid (cost/land/ownership/etc.)
5. Urban power use will remain higher than renewables can create (in Manhattan the use exceeds maximum possible generation by up to 15x)
6. Reliability will continue to be a critical metric
7. Reasonable costs will continue to be a critical metric
8. Electricity is critical to the economy and stability of the US

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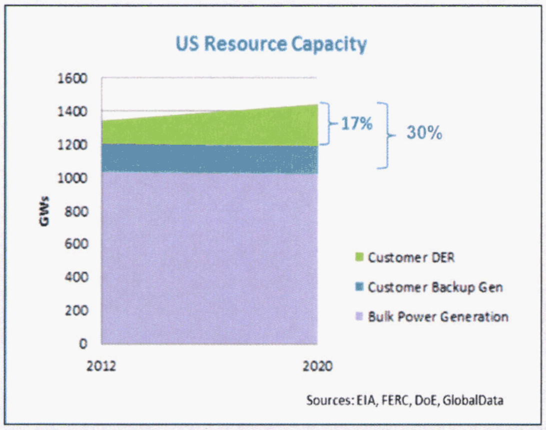
DER will reach 30% of Installed US Capacity by 2020

Effectively all incremental growth in capacity will come from customers



Backup Generation:	225 GW
CHP:	122 GW
Demand Response:	90 GW
Solar PV:	50 GW
Other DG:	25 GW
Dist. Storage:	3 GW
Potential DER Total:	*515 GW*

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Operational Challenges

- Changes to Net Load Curves and Real-time Dispatch Needs
- Distribution Voltage and Power Quality Impacts
- Multi-directional power flow at scale
- Policy enabled customer participation in market and grid operational services
- Power quality and phase imbalance issues
- Shortening decision time frames
- Localized imbalances (supply-demand)

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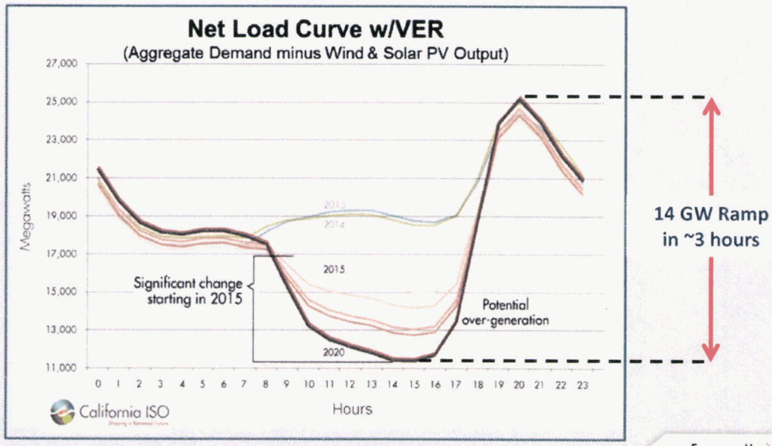
Changing Bulk System Operations

Wind & Solar PV and Customer Load Optimization changing operating conditions – Role for flexible DER?



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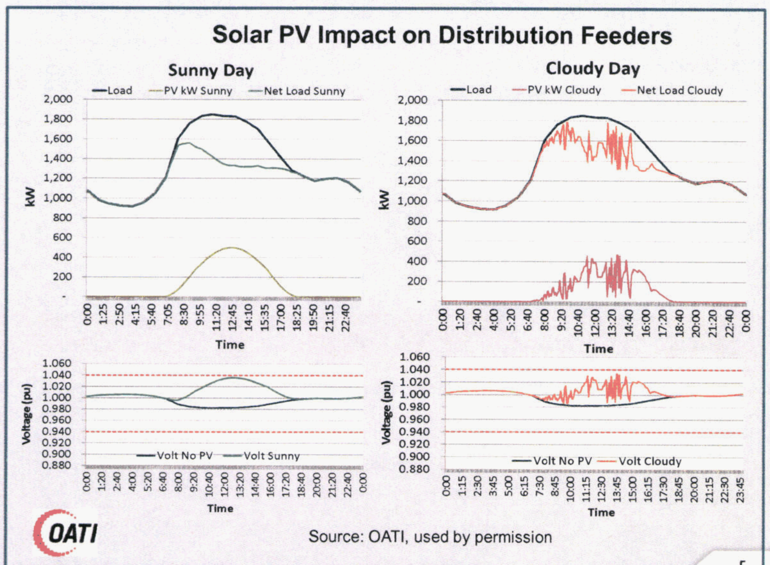
Distribution Power Quality Impacts



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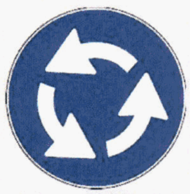
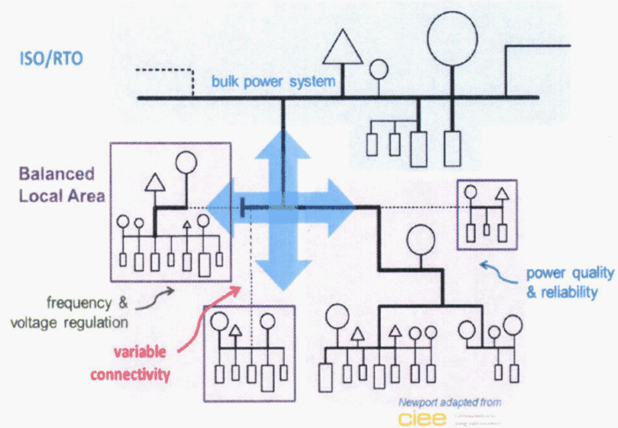
Multi-directional Power Flow

- Need for local balancing & distributed markets to integrate customer DER?





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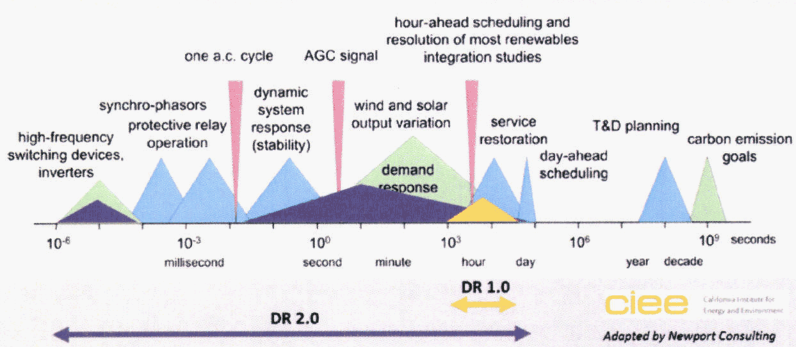
Decision & Response Times Collapsing

Increased Variability Requiring More Dynamic Operations on Shorter Time Cycles



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Multiple DER Constituents

Market & control systems must be able to reconcile multi-party objectives & constraints related to the same distributed resource

Objectives & Goals

Decision Criteria & Processes

Constraints

Value Perception

Economic Utility

Willingness & Ability

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What are the issues?

Category	Issue
Reverse Power Flow	Overcurrent protection gets "confused" -> false trips, no trips
	Line regulators get "confused" -> high/low voltage on DG side
Voltage Fluctuation	Capacitor switching, LTC operation, and line VR operation caused by cloud shading.
	Flicker caused by step voltage change during switching.
	Capacitor switching transients (synchronous closing, pre-insertion impedance, point-on-wave)
Modification of Feeder Section Loading	Low/medium PV penetration -> PV offsets load thereby decreasing section loading
	High PV penetration -> PV may exceed base load, capacity sufficient to distribute surplus power?
Increase in Power Losses	PV changes loading (see row above). Impact on losses

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Issues (II)

Fault Current	PV increases fault current. Impact on relay protection.
Unintentional Islanding	Utility system reclosing into live island may damage switchgear and loads.
Ground Fault Overvoltage	Single-phase fault -> TOVs on unfaulted phase.
Harmonics	Harmonics caused by PV inverter
Dynamics	Effect of fast transients caused by cloud shading and system disturbances. Dynamic interaction of transients with other conventional and non-conventional control devices.
Feeder Imbalance	Imbalance caused by uneven distribution of PV causing Neutral-to-Earth voltages, Overloaded Neutrals
Shorter Equipment life	Anecdotal information suggests that appliances, consumer electronics, electric cars, and other equipment can see up to an 80% reduction in useful life

Prices alone will not solve these issues

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Demand Response Types

- Direct load control
- Industrial shedding
- Rolling blackouts
- Tariffs (TOU/CPP)
- Demand limiting
- Incentives (time based rebates)
- Prices to devices
- Auctions

Different customers respond well to different types of DR

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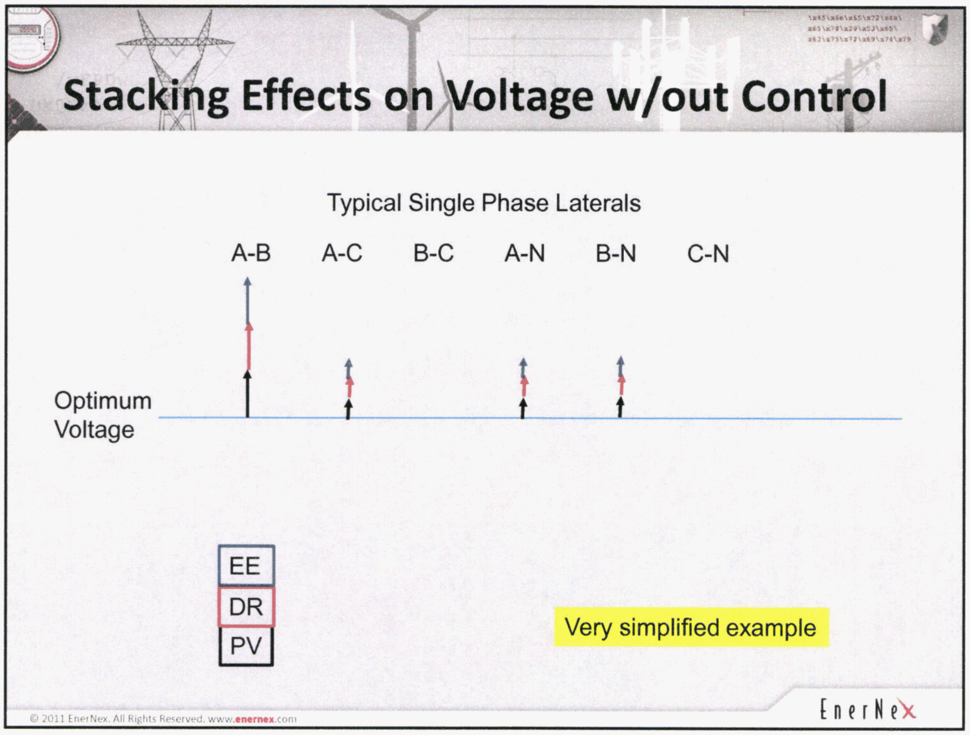
Stacking Effects on Voltage w/out Control
Typical Single Phase Laterals
A-B
A-C
B-C
A-N
B-N
C-N
Optimum Voltage
EE
DR
PV
Very simplified example
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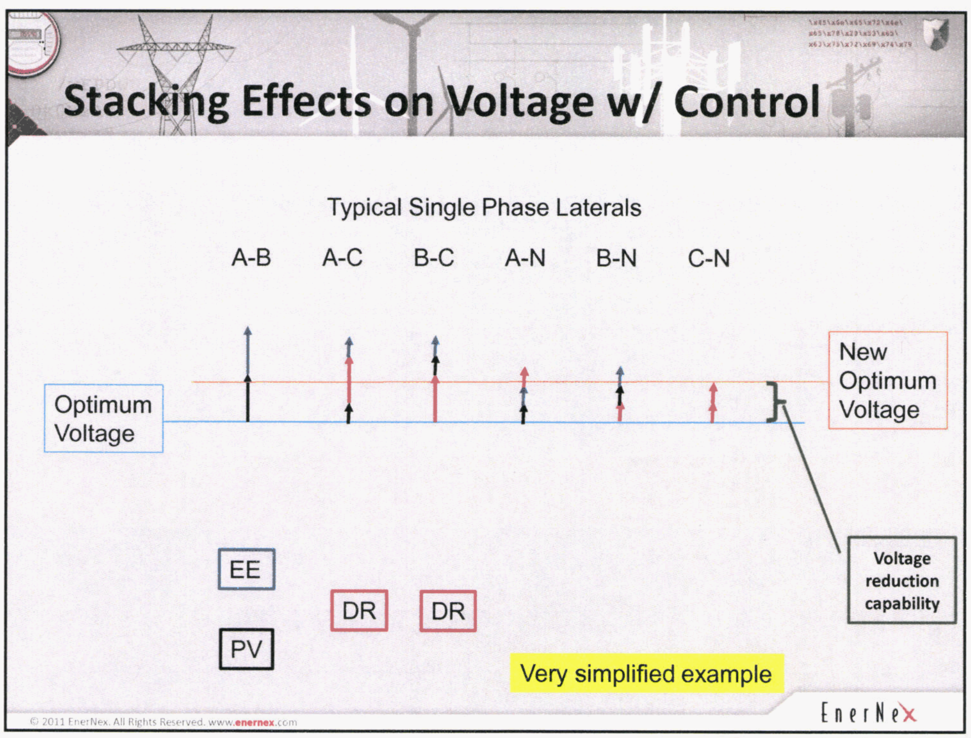
Stacking Effects on Voltage w/ Control
Typical Single Phase Laterals
A-B
A-C
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A-N
B-N
C-N
Optimum Voltage
New Optimum Voltage
Voltage reduction capability
EE
DR
DR
PV
Very simplified example
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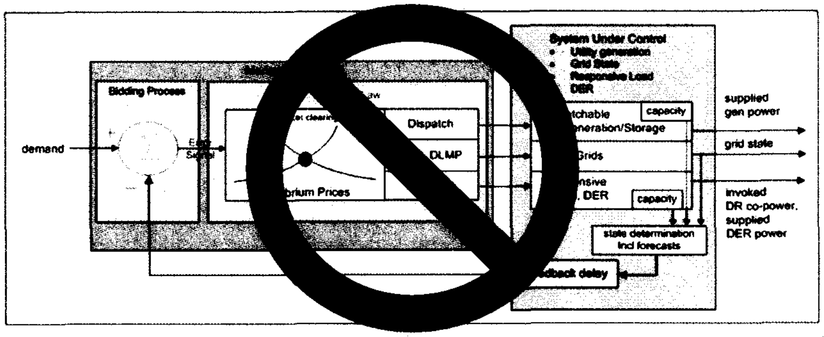
Challenge: Market Structures that Align w/Operational Controls

Current market designs may act as a control element in a feedback control loop, whether intended or not. This loop could be closed around a substantial portion of the power delivery system, including multiple operational tiers as illustrated. Feedback of state variable (not system outputs) causes the equilibrium price to move so as to re-establish the balance between supply and demand, and moves in the equilibrium price cause changes in available generation, DR and DER.



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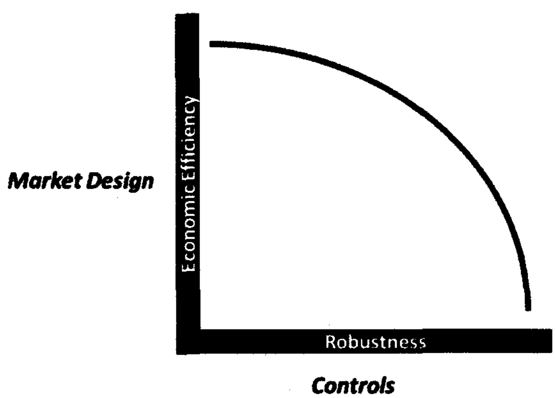
Transactive Energy = Economics + Controls

Operational Optimization with pervasive DER requires more than market efficiency – it requires joint optimization with real-time operational controls across Bulk power system & Distribution



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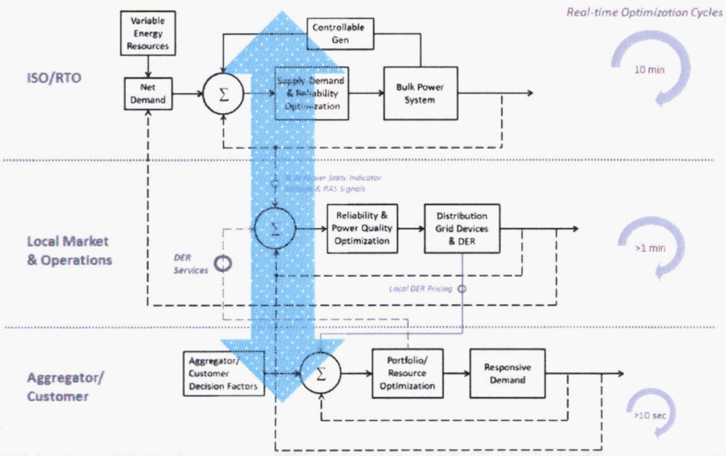
Distributed Controls Across 3 Layers

Need Coordinated Optimization at Each Layer



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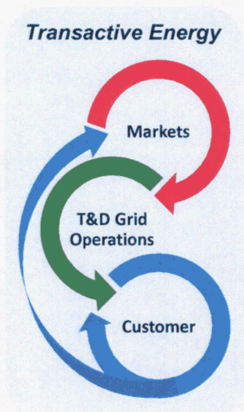
Transactive Energy: Engineering-Economic Based Operational Controls

"Transactive Energy is the ability of customers and others, using value driven control systems, to optimize their use and sale of electric services to markets and grid operators to enhance economic efficiency and reliability."

- Addresses need for reconciliation of converging multi-party business and operational objectives and constraints
- Not just markets, but also a broader integrated cyber-physical control system to ensure reliable electric services



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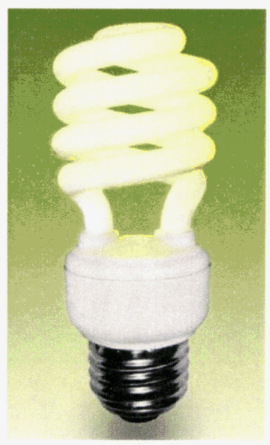
The SPP Difference

- Relationship-based
- Member-driven
- Independence Through Diversity
- Evolutionary vs. Revolutionary
- Reliability and Economics Inseparable



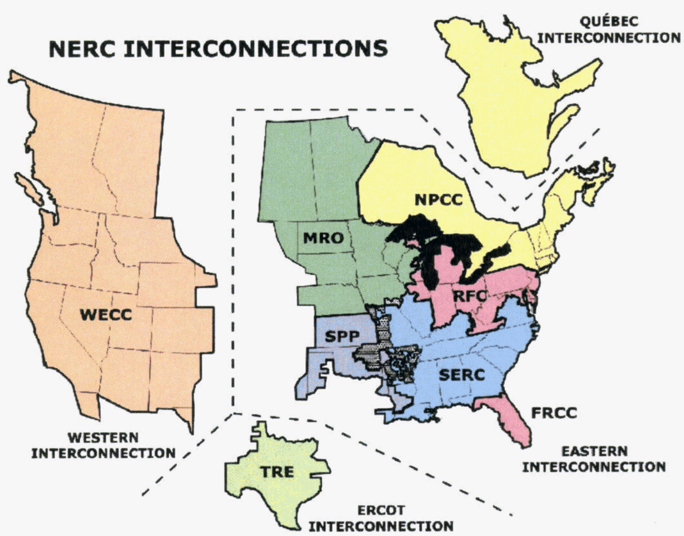
SPP | 2

Regulatory Environment

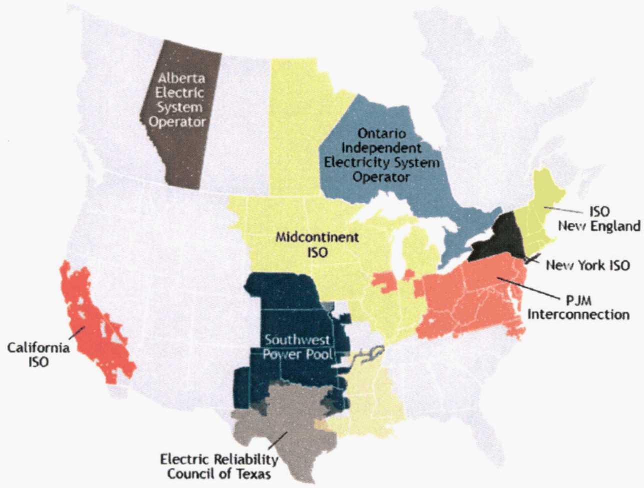
- Incorporated in Arkansas as 501(c)(6) nonprofit corporation
- FERC — Federal Energy Regulatory Commission
  - Regulated public utility
  - Regional Transmission Organization
- NERC — North American Electric Reliability Corporation
  - Founding member
  - Regional Entity

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

3 Electric Interconnections / 8 NERC Regions



Independent System Operator (ISO) / Regional Transmission Organization (RTO) Map



SPP | 5

Our Membership Profile

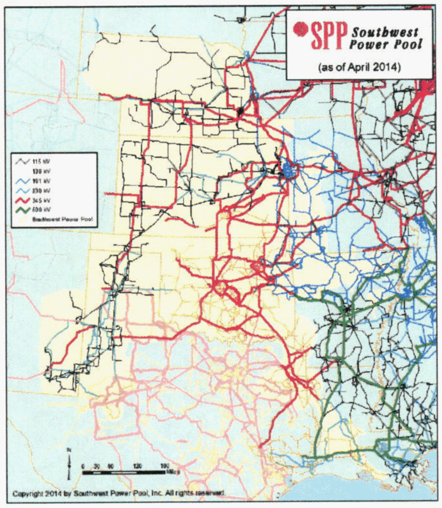
Category	Number
Investor Owned Utilities	14
Cooperatives	13
Marketers	12
Municipals	11
Independent Power Producers/ Wholesale Generation	11
Independent Transmission Companies	10
State Agencies	5
TOTAL	**76**

As of April 11, 2014

SPP | 6

Operating Region

- 370,000 miles of service territory
- More than 15 million people
- 627 generating plants
- 4,103 substations
- 48,930 miles transmission:
  - 69 kV – 12,569 miles
  - 115 kV – 10,239 miles
  - 138 kV – 9,691 miles
  - 161 kV – 5,049 miles
  - 230 kV – 3,889 miles
  - 345 kV – 7,401 miles
  - 500 kV – 93 miles



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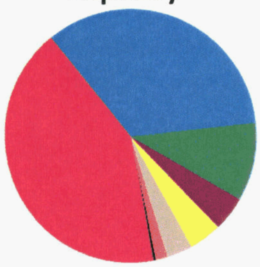
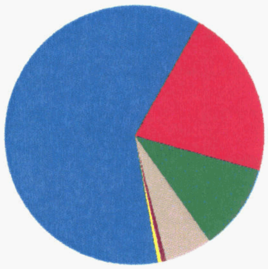
2013 Energy Capacity and Consumption

Capacity



Gas	42.04%
Coal	34.08%
Wind	10.01%
Hydro	4.55%
Dual Fuel	4.06%
Nuclear	3.34%
Fuel Oil	1.83%
Other	0.08%

Consumption



Coal	61.2%
Gas	21.2%
Wind	10.8%
Nuclear	6.0%
Hydro	0.6%
Diesel Fuel Oil (DFO)	0.3%

12% annual planning capacity requirement

SPP | 8

Market Facts

- 102 participants
- 627 generating resources
- 2013 EIS transactions = $1.29 billion

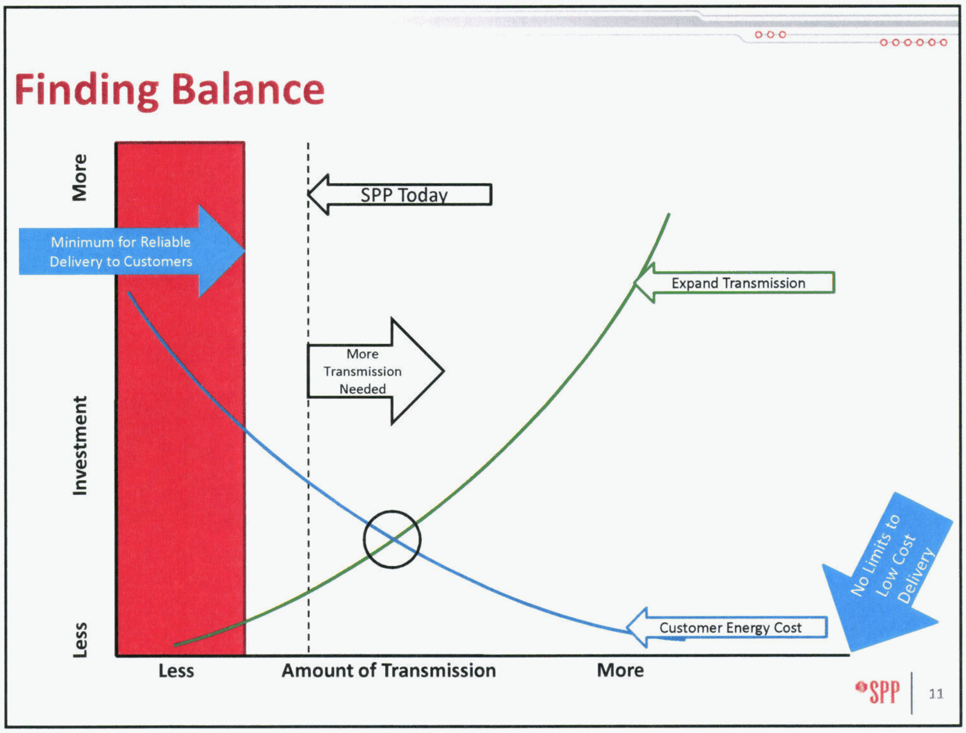
  (Integrated Marketplace went live March 1, 2014)
- 46.3 GW coincident peak load
- 1,563 MW wholesale demand response

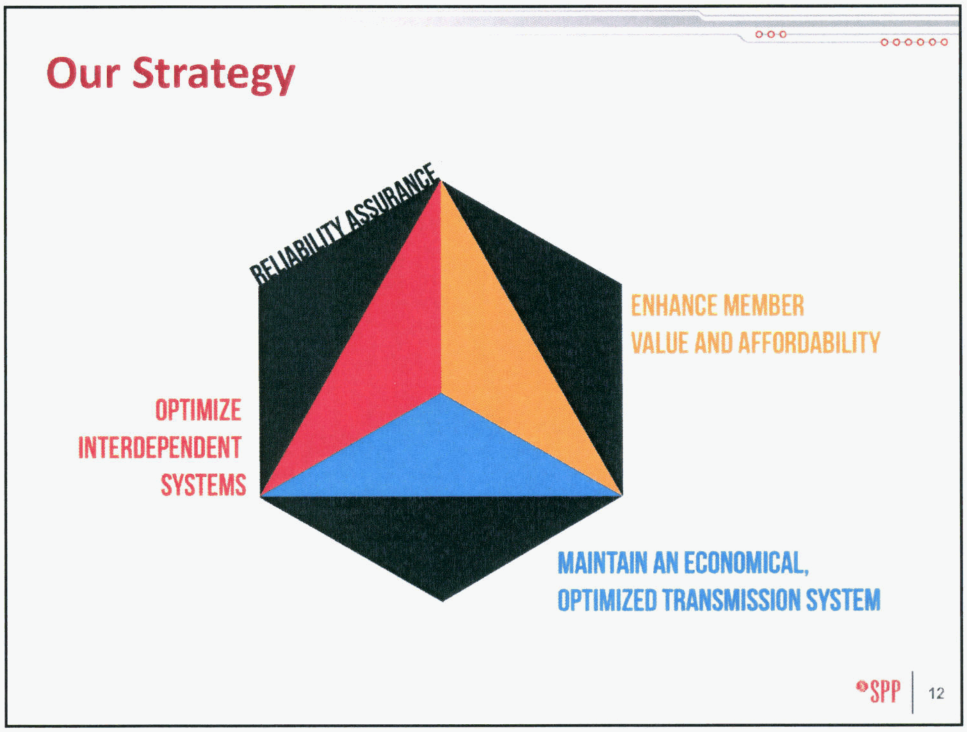
SPP | 9

Contract Services

- Alternative to RTO membership for Transmission Owners
- Oversight of Transmission Owners' system operations:
  - Reliability Coordination
  - Transmission Planning
  - Tariff Administration
  - Interregional Coordination
- Provides process for assigning cost responsibility for transmission upgrades

SPP | 10


Finding Balance
More
Investment
Less
Minimum for Reliable
Delivery to Customers
SPP Today
More
Transmission
Needed
Expand Transmission
No Limits to
Low Cost
Delivery
Customer Energy Cost
Less
Amount of Transmission
More
SPP
11


Our Strategy
RELIABILITY ASSURANCE
ENHANCE MEMBER
VALUE AND AFFORDABILITY
OPTIMIZE
INTERDEPENDENT
SYSTEMS
MAINTAIN AN ECONOMICAL,
OPTIMIZED TRANSMISSION SYSTEM
SPP
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What kind of markets does SPP operate?

- Transmission Service: Participants buy and sell use of regional transmission lines that are owned by different parties
- Integrated Marketplace: Participants buy and sell wholesale electricity in day-ahead and real-time
  - Day Ahead Market commits the most cost-effective and reliable mix of generation for the region
  - Real-Time Balancing Market economically dispatches generation to balance real-time generation and load, while ensuring system reliability.

Market Concepts – What is a Market?

General Concepts:

- Buyers/Sellers OR Producers/Consumers
- Prices driven by Supply and Demand
- Products

Market Concepts – What is a Market? (cont'd.)

Wholesale Energy Market:

Sellers/ Producers
- Utilities
- Municipals
- Independent Power Producers
- Generators
- Power Marketers

Buyers/ Consumers
- Utilities
- Municipals
- Load Serving Entities (LSEs)
- Power Marketers

Locational Prices
- Driven by Supply and Demand at defined locations

Products
- Energy
- Operating Reserves
- Congestion Rights

Integrated Marketplace Overview

Key Components
- Day-Ahead (DA) Market
- Real-Time Balancing Market (RTBM)
- Transmission Congestion Rights (TCR) Market

Products
- Energy
- Operating Reserve (Regulation Up, Regulation Down, Spinning, Supplemental)
- Congestion Rights

Independent monitors ensure markets operate as designed and are efficient/effective

- SPP's internal Market Monitoring Unit (MMU) reports directly to the Board and Oversight Committee
  - Independent from SPP Regional Transmission Organization
- FERC Order 719 allows ISO/RTO markets to be overseen by internal, external, or hybrid monitor
  - 2 ISOs/RTOs have external, 2 have internal, 2 have hybrid
  - SPP's use of internal MMU brings cost-savings and allows easy access to real-time operations
- MMU reviews real-time/historic data and reports any issues to FERC for investigation

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Integrated Marketplace Benefits

- Net Benefits estimated at approximately $100 million/year
- Reduce total energy costs through centralized unit commitment while maintaining reliable operations
- Day-Ahead Market allows additional price assurance capability prior to real-time
- Operating Reserve products support implementation of the SPP Balancing Authority (BA) and facilitate reserve sharing

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What is "SPP EIS" Market?

- The SPP EIS Market provides asset owners the *option* to offer their resources into the marketplace for use in providing Energy Imbalance.
- SPP owns the responsibility to account for and financially settle all EIS amounts. (SPP remains revenue neutral)
- The SPP EIS market doesn't supersede any MP's obligations to any other capacity or ancillary service obligations.
  - Balancing Authorities (BA) and asset owners will continue to use the same procedures used today to manage capacity adequacy, reserves, and other reliability-based concerns.
- All MPs with load and/or resources must register with the SPP Market footprint and are subject to EIS under this market.

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What is and is not EIM?

- Is not
  - An RTO
  - Mandatory
  - Forcing one tariff for transmission service
- Is
  - An option to reduce the cost of energy
  - An assistance to meeting variable generation
  - A transparent price for energy
  - Input into transmission planning

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Benefits of the SPP EIS Market

- **Economic**
  - $170MM in 2013
  - Owners benefit from pooling their resources and gaining access to lower, more transparent pricing.
    - Generators get benefit by reducing their generation and buying lower cost energy from the SPP market, and by offering their generation into the marketplace for exposure to an increased customer base. Generators can operate more closely operate to their economical efficiency point.
    - LSEs benefit from more efficient competition among suppliers (generators) which should lower spot energy prices.
  - Sets Market Price for Imbalance Energy
  - Transmission system capacity is used with greater efficiency

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Benefits of the SPP EIS Market

- **Reliability**
  - More generation for faster response to reliability, for thermal, stability, and voltage limits or issues
  - Faster market system reaction to sudden changes on the system
  - Increased RC information and tools to eliminate slow resource response in provided needed relief
  - Increased visibility for RC or MO to identify resources contributing to ACE excursions and loading of transmission
  - Reduced BA reserve requirements for Schedule or Load ramping
  - More effective management of congestion on local areas including those that have little to no tagged transaction impacts (Nodal generation level congestion management)

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Benefits of the SPP EIS Market

- Reliability Adjuncts
  - Effectively manage congestion on multiple flow gates at the same time and resolve complex congestion situations that have resources that are incremental and decremental to different constraints
  - Identifies and encourages non-dispatchable resources to provide relief
  - More accurate and equitable relief obligations
  - Can effectively and automatically provide relief on external flow gates if needed
  - Ability to "Sell" Non-Firm energy during potential EEA situations
  - Transmission Planning learns from 5 minute dispatch pricing (Valiant-Lydia corridor & NW Texarkana are great examples)
  - Enhances Outage Coordination

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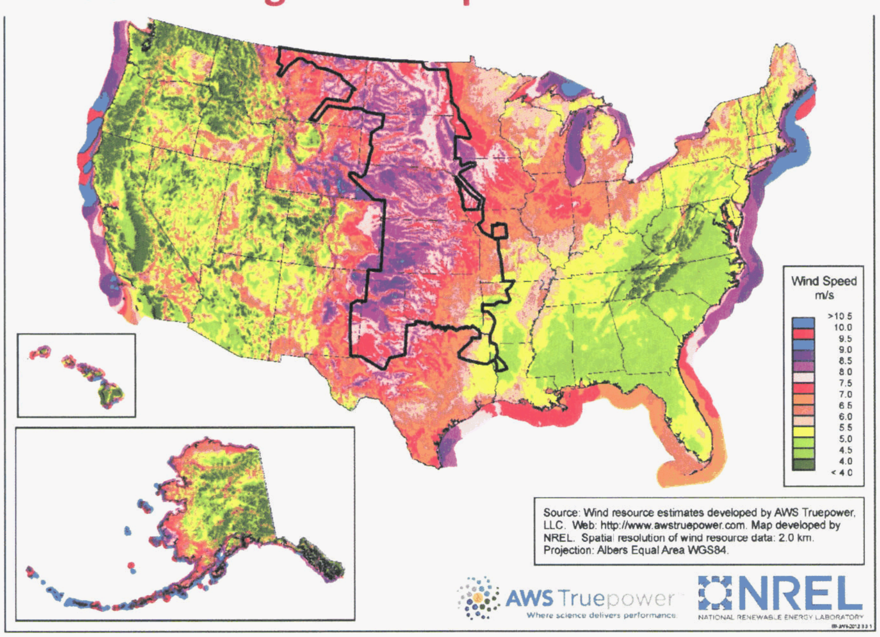
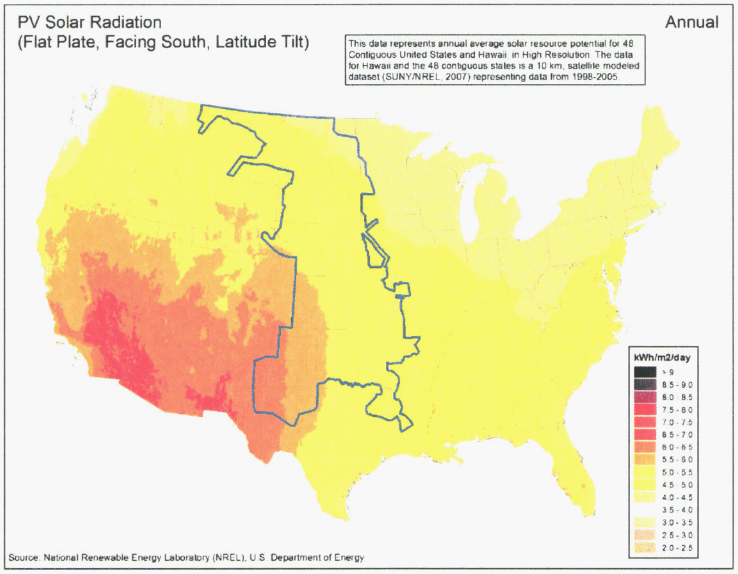
Annual Average Wind Speed - 80 meters



Solar in the U.S.



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California ISO
Shaping a Renewed Future

Briefing on Energy Imbalance Market

Arizona Corporation Commission
Emerging Technologies Workshop
August 18, 2014

Agenda

- Overview of the ISO and the western energy market
- Overview of energy imbalance market
  - Market design
  - Implementation status
  - Next steps
- Governance and the Transitional Committee

California ISO

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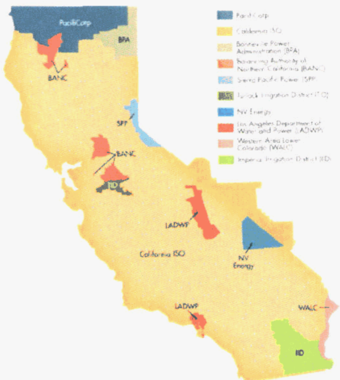
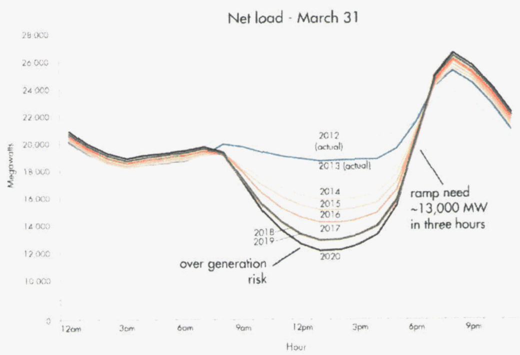
California ISO



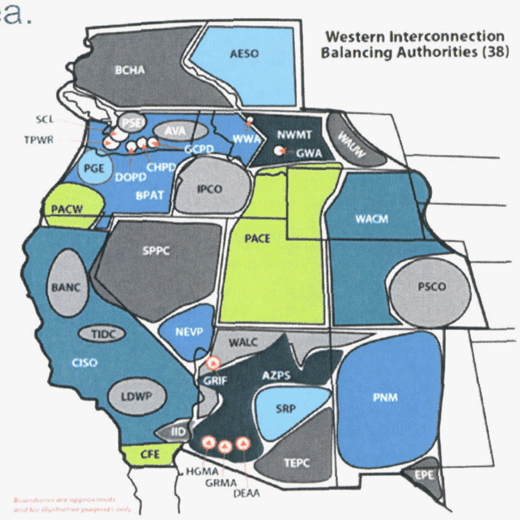


- **60,703** MW of power plant capacity (net dependable capacity)
- **50,270** MW record peak demand (July 24, 2006)
- **30 million** people served

California ISO

With energy imbalance market (EIM), a balancing authority (BA) is still responsible for operating a transmission control area.

- It builds on existing platform, no critical mass required
- Easily scalable, offering low-cost, low risk option to new entities with no exit fees
- EIM is an important tool for renewable integration
- It matches generation with load and maintains frequency
- Preserves BA autonomy, compliance, balancing, reserve obligations



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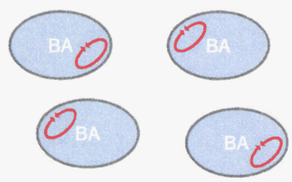
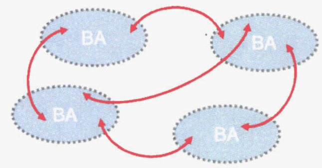
Today vs. EIM

Today:
Each BA must balance loads and resources within its borders.



- Limited pool of balancing resources
- Inflexibility
- High levels of reserves
- Economic inefficiencies
- Increased costs to integrate wind/solar

In an EIM:
The market operator automatically dispatches participating resources across BAs to balance energy



- Diversity of balancing resources
- BA enables resources to participate
- Increased flexibility
- Decreased flexible reserves
- More economically efficient
- Decreased integration costs

Benefits of an energy imbalance market

- Enhances integration of renewable resources by dispatching every five minutes across a larger region.
- Provides reliability and economic benefits to all participants.
  - Reliability through real-time visibility across all balancing authorities
  - Geographical diversity of load and resources
  - Balances in real-time with least cost generation
- Additional benefits outlined in FERC staff paper on qualitative assessment of reliability benefits of EIM:
  - http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

EIM provides significant net benefits

	ISO/ PacifiCorp study (in millions)	**ISO/NV Energy study on incremental benefits** (in millions)	**APS** (in millions)
annual benefits	\$21.4 - \$129.0	\$9.0 - \$18.0 (2017) \$15.0 - \$29.0 (2022)	TBD
start-up costs	approx. \$20.0 (\$2.5 to ISO)	approx. \$11.20 (\$1.10 to ISO)	TBD (≈\$1.0 to ISO)
annual on-going costs	approx. \$3.00 (\$1.35 to ISO)	approx. \$2.60 (\$0.75 to ISO)	TBD (≈\$0.65 to ISO)

Benefits primarily derived from:

- Reduced flexibility reserves
- More efficient dispatch
- Reduced renewable energy curtailment

California ISO

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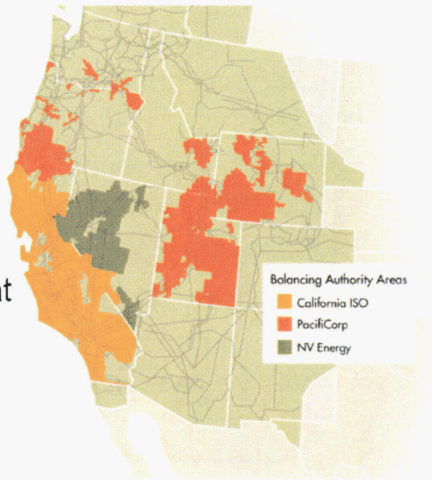
ISO will track EIM regional benefits and provide quarterly reports to stakeholders

- Will compare dispatch cost to a case without EIM
- Quantify imbalance energy <u>dispatch</u> benefits that enable:
  - real-time economic transfers
  - new balancing resources
  - efficient and secure dispatch
- Quantify <u>flexibility</u> benefits that enable:
  - diversity to reducing flexibility reserves
  - sharing and compensation of flexibility reserves



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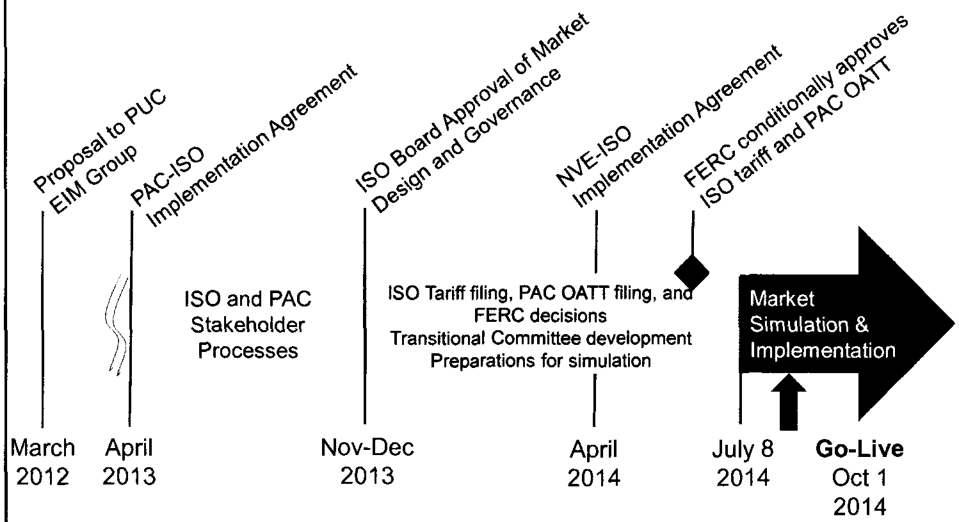
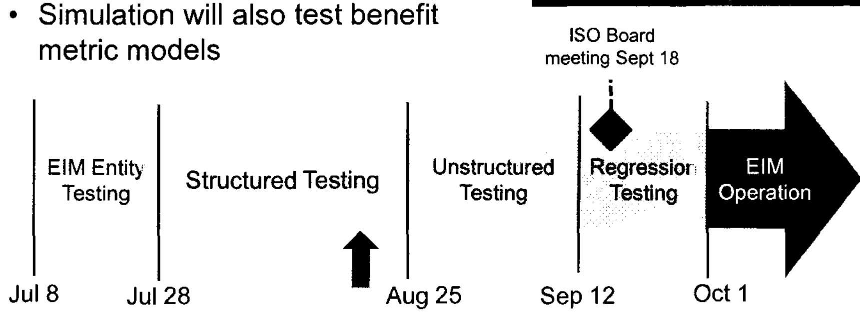
EIM stakeholder process and milestones

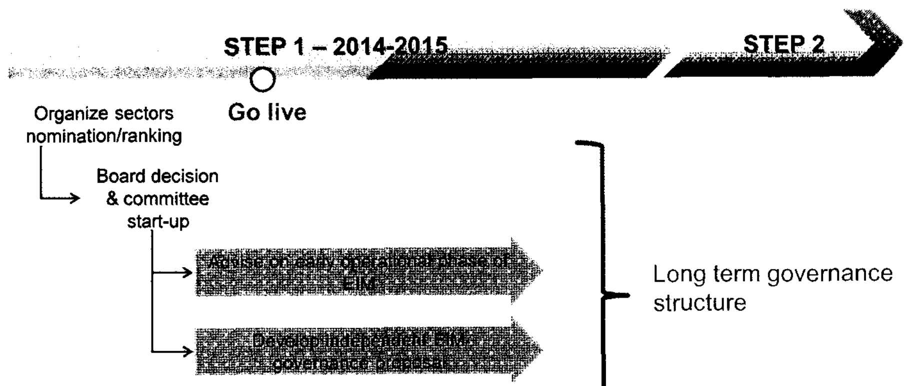


Status of implementation

- EIM network model and system changes
- Operations readiness
- Market simulation July 8–Sept 12
- Regular participant conference calls
- Simulation will also test benefit metric models



Governance proposal designed to give regional entities a voice in decision-making



Stakeholder Transitional Committee

- Advisory committee to ISO Board
- 11-12 members
- Open meeting policy

California ISO

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Transitional Committee appointed in May 2014

1. **Stephen Beuning,** Xcel Energy, Inc.
2. **Tony Braun**, Braun Blaising McLaughlin & Smith, PC (representing CA Municipal Utility Association)
3. **Dede Hapner**, Pacific Gas and Electric Company
4. **Natalie Hocken**, Representative from EIM Entity PacifiCorp
5. **Travis Kavulla**, Commissioner, Montana Public Service Commission
6. **Kevin Lynch**, Iberdrola Renewables
7. **Mark Smith**, Calpine Corporation
8. **Walter Spansel**, Representative from EIM Entity NV Energy
9. **Rebecca Wagner**, Commissioner, Public Utilities Commission of Nevada – **CHAIR**
10. **Robert Weisenmiller**, Chair, California Energy Commission
11. **Carl Zichella**, Natural Resources Defense Council

California ISO

The committee will hold public meetings throughout the west

- Committee will meet at least as often as the ISO Board of Governors
- ISO liaison will attend meetings and facilitate additional support as needed to the committee.
- Development of long-term EIM governance structure
  - May include defined authority over EIM matters
  - Members are independent from EIM market participants
  - Provides a meaningful and clear role for the EIM body
  - Remains nimble, to allow for efficient decision-making
  - Includes a mechanism to resolve any disagreements between the EIM governance body and the ISO Board
  - Allows for the efficient and meaningful EIM market oversight

Summary

- EIM provides reliability and financial benefits to California and other participants in the West
- CAISO proposal based on existing platform provides a more flexible and scalable approach at far less cost to other balancing authorities
- EIM implementation helps facilitate renewable integration
- CAISO Transitional Committee (regional members) will provide immediate voice for region and offer recommendations on independent governance structure for EIM matters

Computer based training (CBT) is available for EIM

- Introduction to the Energy Imbalance Market

  This Computer Based Training provides a high level overview of the Energy Imbalance Market

  http://content.caiso.com/training/Introduction%20to%20EIM/My%20Articulate%20Projects/Introduction%20to%20the%20Energy%20Imbalance%20Market/player.html

- How the Energy Imbalance Market Works –

  This Computer Based Training describes the roles and responsibilities of the key players in EIM and the business processes that will take place.

  http://content.caiso.com/training/HowEIMWorks/player.html

California ISO

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For Transitional Committee meeting information, please see http://www.caiso.com/informed/Pages/BoardCommittees/EnergyImbalanceMarketTransitionalCommittee/Default.aspx

Questions

Contact the California ISO
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Director, Regional Affairs
scrowley@caiso.com
(916) 608-7130

California ISO

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Energy Imbalance Market Key Questions

Submitted by Amanda Ormond, Managing Director, Western Grid Group

August 18, 2014, Innovation Workshop

Participating in the Energy Imbalance Market (EIM) will save APS customers an estimated $10-15 million annually[1], while modernizing the operation of the electric grid and improving system efficiency. Most importantly, it will improve the reliability of utility service by providing access to energy when APS experiences energy imbalances.

Regional estimates from the Western Electricity Coordinating Committee and National Renewable Energy Laboratory studies show millions of dollars in savings for Arizona electric consumers from participation in EIM. To determine if EIM is good for individual balancing authorities (e.g., APS and TEP) individual system studies are necessary. Nevada Energy decided to join the EIM in October 2015 as a result of a study of its individual utility system. APS reported in its July 28 presentation in the Innovation Workshop that it is currently conducting a study of EIM.

Given the compelling customer savings, operational efficiency improvement and increase reliability to the state's electric system Western Grid Group poses the following questions:

1. What type of study is APS currently conducting on EIM?
2. For purposes of transparency, will APS have a technical or commission review process as part of the study?
3. Is the study a decision-quality study which will provide the necessary information for APS to determine when/if it will join the EIM?
4. If yes, when will the study be completed and filed at the Commission?
5. On what date can the Commission expect a decision from APS on EIM?
6. If APS determines that it will not join the EIM at the earliest possible date (commitment by fourth quarter, 2014), what information will be provided to the Commission to justify that position?
7. Will APS offer other cost savings for consumers to compensate them for savings foregone by not joining EIM?
8. APS reported that it will be spending $10-15 million in one-time startup costs to upgrade and modernize its billing and settlement systems. How much of these costs are attributable to implementation of FERC Order 764, requiring the utility to offer 15 minute scheduling[2], and how much are for joining the EIM?
9. As revenues generated from the off-system sales from the EIM only accrue to customers and not shareholders, does this create a disincentive for APS to join the EIM as soon as practicable?
10. Should the Commission consider cost sharing of earnings (between customers and shareholders) to ensure that APS is provided with incentives to maximizing revenues from generating units through avenues such as EIM?

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[1] Extrapolated from APS 7/28/14 statement of expected savings of 1-1.5% on system production costs of $1 billion.

[2] Jurisdictional utilities were required by FERC Order 764 to offer 15 minute scheduling by November 12, 2013.

Amendment to the Energy Supply Plans
of
Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
To Reflect Their Participation in the Energy Imbalance Market

Narrative of the Companies' Proposed Participation in the Energy Imbalance Market

TABLE OF CONTENTS

SECTION 1 – EXECUTIVE SUMMARY

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra") (together, the "Companies" or "NV Energy" and individually the "Company") are through this filing, requesting approval of the Public Utilities Commission of Nevada (the "Commission") of an amendment to each Company's Energy Supply Plans ("ESP") to reflect the participation of the Companies in the Energy Imbalance Market ("EIM") that is being established by the California Independent System Operator (the "ISO"). These amendments will enable the Companies to further optimize their power supply portfolios for the benefit of their customers.

The ISO EIM is a voluntary, five-minute balancing market that will cover the NV Energy, PacifiCorp West, PacifiCorp East, and ISO Balancing Authority Areas ("BAAs").[1] In late 2012, the Companies and the ISO embarked on a joint study to estimate and evaluate the costs and benefits for customers of the Companies as a result of participation in the EIM. ABB Inc. ("ABB") and Energy and Environmental Economics, Inc. ("E3") were retained to perform the analysis, which was finalized March 25, 2014, and titled "The NV Energy-ISO Energy Imbalance Market Economic Assessment" ("Economic Analysis").

As described below, economic benefits were estimated using production cost modeling. The Companies and the ISO formed technical teams consisting of various members within each of the two organizations. The preliminary results of the analysis led NV Energy to announce in November 2013 that it intended to pursue participation in the EIM. The Companies made a decision to participate in the EIM after the Economic Analysis became final. The purpose of this filing is to receive approval from the Commission to participate in the ISO EIM. Specifically, the Companies request, pursuant to Nevada Administrative Code Section 704.9494 that the decision of the Companies to add participation in the EIM to their respective portfolio optimization procedures is prudent.

As concluded in the Economic Analysis, the potential benefits to NV Energy's customers outweigh the costs and risks of participating in the EIM. Benefits to customers will include:

- Costs are reduced through the use of an automated system that matches demand with least-cost available resources within transmission constraints in real-time, by making available a larger pool of diverse generation resources from which to obtain power, and by making available an intra-hour market in which Company resources can be used to earn incremental revenue.

---

[1] A balancing authority area ("BAA") is the collection of generation, transmission, and loads within the metered boundaries of a BA. A balancing authority ("BA") is an entity responsible for integrating resource plans in advance of real-time balancing needs, maintaining load-interchange-generation balance within a balancing authority area, and supporting interconnection frequency in real time.

- Reliability is enhanced by increasing visibility, situational awareness, coordination, and automated outage response across larger portions of the western U.S. energy network.

- Integration of renewable energy sources is improved due to load and resource diversity across the large EIM geographic footprint. In addition, the necessity to curtail renewable resources in situations of over-generation is reduced.

The EIM will allow the real time dispatch of power plants between the Companies' BAA and other participating BAAs in the ISO EIM. Participation will also provide flexible reserves to follow variable generation such as wind and solar. Participating in the EIM is forecast to provide economic benefits to both NV Energy customers and other participating BAAs in three areas: 1) interregional dispatch savings, 2) reduced flexible reserves, and 3) reduced renewable energy curtailment. The combined potential annual gross benefits to NV Energy, ISO, and PacifiCorp BAAs, as found in the Economic Analysis, are estimated to range from \$9.2 million to \$18.2 million in 2017 growing to \$15.0 million to \$29.4 million in 2022. The potential annual gross benefits to NV Energy customers are estimated to range from \$6.0 million to \$9.5 million in 2017 growing to \$7.7 million to \$12.2 million in 2022.

The upfront capital investment by NV Energy to implement and integrate the NV Energy system into the ISO EIM is estimated to be \$11.2 million. The ongoing operation and maintenance ("O&M") cost of participating in the ISO EIM is estimated to be \$2.6 million to \$3.2 million. This O&M cost estimate range is based on assumptions about the staffing that will be required to participate in and analyze EIM results. Because the ISO EIM will be a new market, there is uncertainty inherent in estimating the staffing needs. Participation in the EIM is voluntary, and NV Energy may terminate its participation in the EIM with no exit fee in the event the estimated benefits do not materialize or for any other reason.

The ISO is in the process of establishing the EIM, which is scheduled to go live in October 2014, with PacifiCorp as the initial participant. In February 2013, PacifiCorp announced its plan to participate in the EIM and is actively working on the integration of the necessary systems and operations to effectuate its participation. NV Energy will have the benefit of PacifiCorp's experience, which PacifiCorp has shared with NV Energy, and will use these lessons from the initial implementation to assure NV Energy efficiently captures benefits for its customers. An expanded EIM that includes NV Energy would allow EIM participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources between participating BAs.

On a parallel path to this ESP filing, on April 16, 2014, the ISO filed an Implementation Agreement with the Federal Energy Regulatory Commission ("FERC") for approval. The Implementation Agreement, as further discussed below, defines the steps the Companies and the ISO will take to expand the ISO dispatch model to include NV Energy's BAA. It also provides specific milestones and a payment schedule that is in place to assure that key milestones are met before the Companies are required to make payments to the ISO.

It is important to note that the Companies' participation in the EIM does not mean that they are joining the ISO as participating transmission owners or relinquishing control of any of their generation or transmission assets. The Companies will remain responsible, as they are today, for grid reliability and compliance with reliability standards. They will retain control of their generation, purchase power, transmission and distribution assets and will continue to use those to serve load and provide reliable service as they do today. Furthermore, participation in the EIM will not modify the Companies' day-ahead and longer term responsibilities and operations.

The market design policies that are being established for the EIM are consistent with NV Energy's responsibility to protect its customers while also obtaining benefits from the market. Finally, because the ISO is using its functioning market platform for the EIM, it offers less risk and lower costs than could be achieved by creating a new market design and infrastructure.

SECTION 2 – OVERVIEW OF THE INDEPENDENT SYSTEM OPERATOR

The ISO operates the largest wholesale transmission grid in the Western United States, providing open and non-discriminatory access supported by a competitive energy market and comprehensive planning efforts. The ISO opened its Northern and Southern California control centers in 1998 when the state restructured its wholesale electricity industry. While utilities still own transmission assets, the ISO acts as a traffic controller, maximizing the use of the transmission system and its generation resources, and supervising maintenance of the lines. The ISO matches buyers and sellers of electricity, facilitating over 28,000 market transactions each day to ensure enough power is on hand to meet demand.

In April 2009, the ISO implemented a major redesign of California's wholesale energy markets. The redesign created an integrated forward market, improved congestion management, and introduction of locational prices for a more efficient use of resources, and a 5-minute real-time market. Every five minutes the ISO forecasts electrical demand, accounts for operating reserves and dispatches the lowest cost resources to meet demand while ensuring enough transmission capacity is available to deliver the power. This market has operated since 2009 and is the platform for the ISO's EIM, which the ISO will operate and administer.

SECTION 3 – DESCRIPTION OF THE EIM

The ISO's proposed EIM does not represent a new market. It is an expansion of one component of the ISO's existing market. The ISO's proposal takes advantage of its existing real-time market by adding new procedures to accommodate the voluntary participation of other BAs" within the current imbalance market structure. This provides other BAs with access to a real-time market based on a proven structure, which the ISO introduced five years ago.

The ISO's proposed procedures accommodate BAs whose operations in advance of real-time operations (*i.e.*, day-ahead and other forward operations) differ from the ISO's day-ahead market. This allows BAs to participate in the EIM without altering other aspects of their operations and without having to transfer control of their transmission systems or generating units.

Each BA that chooses to participate in the EIM will remain responsible for the reliability of its BAA. This includes operating reserve and capacity requirements, scheduling and curtailment of the transmission facilities under its operational control, and manually dispatching resources out-of-market to maintain reliability. The proposed ISO tariff revisions for implementing the EIM recognize the retention of these responsibilities by participating BAs, as well as elements designed to ensure that each participating BA has sufficient resources to serve load while still realizing the benefits of increased resource diversity.

A. Development of the ISO EIM

In March 2012, the ISO provided the Public Utility Commission-EIM group, a group of 12 western state regulatory commissions, a conceptual proposal under which the ISO would provide energy imbalance services through its existing market platform to BAs that choose to participate. The ISO explained that, under its proposal, interested BAs would have the opportunity to participate voluntarily in the ISO's existing real-time market with a low up-front cost, a proven design, and no exit fee. By using its functioning market platform, the ISO could offer less risk and lower costs than could be achieved by creating a new market design and infrastructure.

Because the ISO did not need to build a new platform for the regional EIM, its proposal offered BAs the opportunity to begin participating in the market when they are ready to do so under a "pay-as-you-go" design. Participants would pay a one-time up-front fee to cover the cost of ISO modeling, licensing, and other preparatory work. Once operational, they would pay ongoing fees based on their level of participation, consistent with the ISO's grid management charge structure.

PacifiCorp expressed interest in the ISO proposal shortly after it was presented. In March 2013, the ISO Board of Governors (the "ISO Board") approved moving forward with PacifiCorp in parallel with an ISO stakeholder process to develop the design of the EIM. On June 28, 2013, the FERC approved an implementation agreement between the ISO and PacifiCorp to account for PacifiCorp's portion of the expansion of the ISO real-time model. ISO and PacifiCorp are in the process of integrating their two systems and are planning on going live with a fully functional EIM in October 2014.

B. EIM Stakeholder Processes

Development of the EIM has been an open and transparent process. In all, there have been three separate stakeholder processes led by the ISO. These included processes on market design, governance, and tariff design. With regard to market design, the ISO held five stakeholder meetings over the course of about six months, including meetings in

Phoenix and Portland to facilitate participation by stakeholders outside of California. In addition, the ISO held five technical workshops to discuss specific design elements of particular interest to stakeholders in more technical detail. All of these materials are available for reference on the ISO website.[2] The ISO prepared detailed comment matrices throughout the stakeholder process, which addressed stakeholder concerns. NV Energy representatives participated throughout the stakeholder process. Broad stakeholder support was voiced in public comments and written submissions. The ISO Board approved the proposed design for the EIM on November 7, 2013.

A separate ISO stakeholder process addressed governance issues associated with the EIM. As part of this process, the ISO Board approved a charter in December 2013 for a transitional committee to advise it on matters relating to the EIM and to develop a proposal for an independent governance structure for the EIM. The ISO anticipates that this committee will engage in the consideration of future design features and enhancements.

A third ISO stakeholder process related to tariff changes necessary to implement the market design. A result of this process was the ISO's February 28, 2014, filing with FERC of revisions to its tariff to implement the EIM (Docket ER14-1386). On March 31, 2014, the Companies intervened in that filing, in support of the ISO's development of the EIM.

In addition to the ISO's stakeholder processes, NV Energy has conducted three formal workshops in the first quarter 2014 with the Regulatory Operations Staff of the Commission ("Staff"), Commission Advisors, and the technical staff of the Attorney General's Bureau of Consumer Protection ("BCP"). The purpose of the workshops was to inform the regulatory bodies of the plan, review the technical merits and economics, and seek input on the merits of NV Energy participating in the ISO EIM. Representatives from the ISO also attended the workshops. NV Energy appreciates the time that Staff, Commission Advisors and the BCP have dedicated to learning about the EIM and the thoughtful discussions that took place in these workshops.

Finally, the Companies will initiate a stakeholder process for their transmission customers and other stakeholders focused on the key elements of the ISO EIM, what steps customers will need to take in order to participate in the EIM, and review of changes to the Companies' Open Access Transmission Tariff ("OATT") that will be made for the Companies to participate in the EIM.

C. EIM Participation

Figure 1 below illustrates the ISO, PacifiCorp, and NV Energy BAAs and helps to show the regional nature of the EIM and the geographical diversity that enhances the benefits of the EIM.

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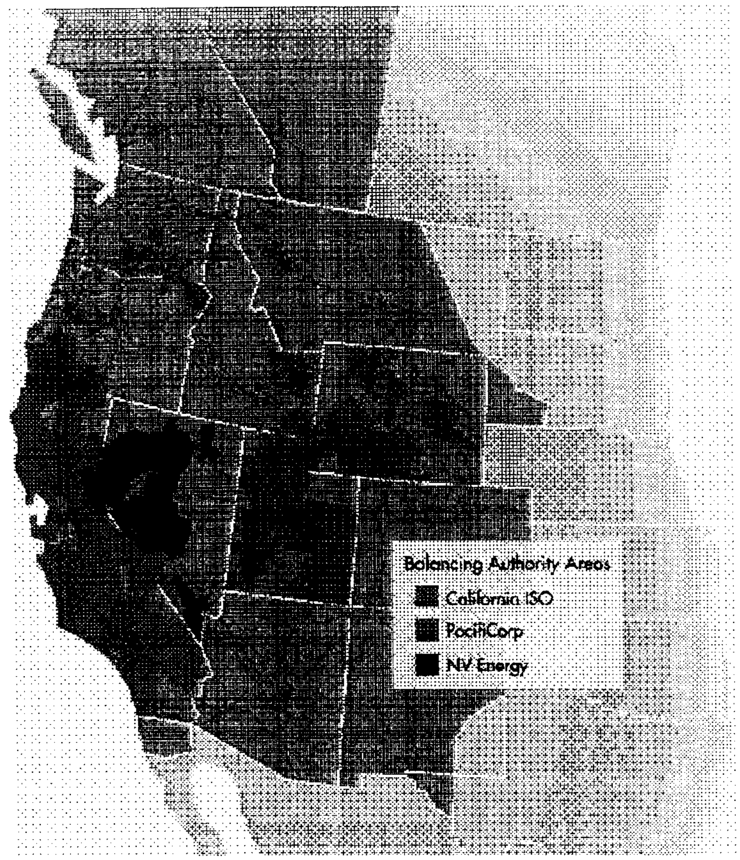
[2] http://www.caiso.com/informed/pages/StakeholderProcesses/EnergyImbalanceMarket.aspx.

Figure 1 - NV Energy/ISO/PacifiCorp EIM Footprint



Participation in the EIM will be open to non-NV Energy generators within NV Energy's BAA. Any party within NV Energy's BAA wishing to participate would need to be an eligible customer under the NV Energy OATT, meet the EIM requirements of both the Market Operator (the ISO) and the EIM Entity (NV Energy). Similarly, generators within the NV Energy BAA may choose not to participate in the EIM.

The operation of the EIM will include the following types of entities or functional roles:

1. <u>EIM Entity</u>: The EIM Entity is a BA that elects to participate in the EIM. Proposed section 29.2 of the ISO tariff sets forth the process for becoming an EIM Entity, with the pre-market operation particulars and initial fee to cover the costs associated with including its BAA in the EIM to be included in an implementation agreement. As an EIM Market Participant, the EIM Entity is responsible (1) for identifying available transmission intertie capacity from participating transmission service providers in its BAA for use in the ISO's real-time market and,

(2) for scheduling all load and resources in its BAA that do not participate in the real-time market (known as non-participating load and non-participating resources) and for paying EIM charges related to non-participating load and non-participating resources. NV Energy will be an EIM Entity.

2. EIM Entity Scheduling Coordinator: The EIM Entity Scheduling Coordinator is the entity through which the EIM Entity provides information to the real-time market. In order to prevent the inappropriate sharing of information regarding transmission and generation, an EIM Entity Scheduling Coordinator cannot be a scheduling coordinator for a supply resource unless it is a transmission provider subject to FERC standards of conduct in 18 C.F.R. § 358.

3. EIM Participating Resources ("EPR"): EPRs are the owners or operators of EIM resources that wish to bid supply into the real-time market. EPRs can be generating units, load, demand resource providers, or other resources qualified to deliver energy or similar services, such as non-generation resources. Each type of resource that is eligible to participate in the current ISO real-time market is eligible to participate through the EIM, but only if the EIM Entity supports participation by that type of resource and the resource meets the technical requirements for such participation.

4. EIM Participating Resource Scheduling Coordinator: The EIM Participating Resource Scheduling Coordinator is the entity through which the EIM Participating Resource participates in the real-time market. To prevent the inappropriate sharing of information regarding transmission and generation, an EIM Participating Resource Scheduling Coordinator cannot be an EIM Entity Scheduling Coordinator unless it is a transmission provider subject to FERC standards of conduct in 18 C.F.R. § 358.

5. Market Operator: The ISO will perform the role of the Market Operator. The Market Operator performs the following functions: 1) forecast expected imbalance energy requirements, 2) clear bid offers to meet expected imbalances, 3) produce prices used for settlement of imbalance energy, and 4) settle imbalance energy. The Market Operator settles imbalance energy with the EIM Participating Resource Scheduling Coordinator for all EIM Participating Resources and with the EIM Entity Scheduling Coordinator for all non-participating resources.

D. Operation of the EIM

The EIM Entity Scheduling Coordinator ensures and informs the Market Operator of the resource plan that balances EIM Entities' forecast demand plus exports. This plan may be made of both resources inside the EIM Entity BAA or imports from other BAAs.

The EIM Entity Scheduling Coordinator will submit the balanced BAA base schedule and resource plan to the Market Operator. Also, prior to the start of the EIM, the Market Operator will evaluate the BAA base schedule and provide advisory information back to the EIM Entity Scheduling Coordinator to provide an opportunity for the EIM Entity to ensure the BAA base schedule is balanced and feasible from a congestion perspective. Separately, an EIM Participating Resource Scheduling Coordinator will submit to the Market Operator bid offers for increased or decreased dispatch for EIM Participating Resources relative to their individual base schedules.

The Market Operator will optimize all real-time bid offers, using a security constrained economic commitment and dispatch process every 15 and 5 minute interval of each hour for which the EIM Participating Resource was offered for EIM dispatch. Since a resource may have some of its capacity committed to the BA for operating reserve or regulation the EIM Entity Scheduling Coordinator shall also inform the Market Operator of such committed resource capacity so that the Market Operator does not dispatch such committed resource capacity via the EIM.

The Market Operator will issue dispatch instructions and compensate EIM Participating Resources through the EIM Participating Resource Scheduling Coordinator. The Market Operator will settle and allocate imbalance and other associated costs that are attributable to the EIM BA to the EIM Entity Scheduling Coordinator. The EIM Entity will allocate such costs to its customers pursuant to its OATT.

E. Key Elements of the EIM Market Design

In consideration of participating in the EIM, NV Energy reviewed key elements of the market design throughout the stakeholder process. Significant elements of the market design review are described below:

Resource Sufficiency: Some entities in the West have expressed concern about the possibility that entities would "lean" on the EIM to provide them access to energy if they were not sufficiently resourced to serve their load. To address this concern, the EIM is designed to ensure that each participating BA has sufficient resources to serve load. The ISO does this by performing a series of tests each hour, including a flexible ramping sufficiency test. The ISO will impose limitations on transfers into or out of an EIM Entity that fails the test, thereby ensuring that each EIM Entity has sufficient resources to avoid leaning.

California Greenhouse Gas Costs: The market design also recognizes the need for resources that serve load in the California ISO BAA through the EIM to comply with California's greenhouse gas ("GHG") cap and trade regulations. As it currently does for resources participating in its real-time market, the ISO will allow EIM Participating

Resources to include the costs of compliance in their energy bids and will incorporate this cost into its dispatch of generation as appropriate. However, in the EIM the ISO will not consider this GHG compliance cost when it dispatches generation that is attributable to serving load outside the ISO BAA. As a result, California GHG compliance costs will not be passed to non-California load, including NV Energy customers.

<u>Transmission Capacity Use</u>: NV Energy anticipates use of "as available" Available Transmission Capacity ("ATC") for EIM transactions. Studies to date indicate that existing, non-committed ATC between NV Energy and the ISO would be sufficient to meet anticipated levels of EIM transactions. Additionally, this methodology would not impact existing or potential users of the transmission system negatively as the capacity could still be used for existing tariff products like Network Integration Transmission Service or Point-to-Point Service. The Company expects to file revisions to its OATT in early 2015 to allow the FERC to review NV Energy's OATT revisions and issue an order prior to the expected October 2015 "go-live" date.

<u>Transmission Charges</u>: Transmission access to the EIM will be provided under the applicable transmission service provider tariffs. As part of a reciprocal arrangement between EIM Entities, initially it is anticipated that there will be no incremental transmission charge for the use of transmission to support EIM transfers between participating BAs. EIM Participating Resources within NV Energy's BAA would be required to have sufficient transmission service in accordance with their needs on an hourly or greater basis. This practice is intended to eliminate use of EIM by non-paying parties. Within the first year of operation, before NV Energy is expected to participate, the ISO and PacifiCorp will consider in consultation with stakeholders whether to continue this reciprocity arrangement or make modifications.

<u>Market Oversight</u>: The EIM includes market monitoring which will be provided by the ISO Department of Market Monitoring. Related, the ISO will use a process based on its existing local market power mitigation approach to mitigate market power in each participating BA and assess the application of market power mitigation before and after implementation.

SECTION 4 – ECONOMIC ANALYSIS

A. Modeling Approach

The ISO and NV Energy retained the services of ABB and E3 Consulting to perform the economic analyses of the benefits of NV Energy participating in the ISO EIM and document the findings. ABB used its proprietary production cost software GridView. E3 was retained to perform the economic analysis and document the results. E3 has direct experience with the economic analysis and was the consultant that performed the economic analysis on the PacifiCorp-ISO EIM benefit study. The E3 final report is included as Technical Appendix Item 1.

The core of GridView is a transmission constrained economic dispatch algorithm. GridView mimics the operation of an electric market by dispatching generating units based on their bid prices while taking into account the flow limits on transmission lines and interfaces under normal, as well as contingency conditions. The outputs of GridView are information such as hourly unit dispatch, locational marginal prices ("LMPs") at buses, flow on lines and congestion cost of limiting lines.

GridView determines the least-cost security constrained dispatch of generating units to satisfy a given demand, based on dispatch according to their variable costs. The major advantage of GridView is its ability to simulate the hourly operation of generating units and transmission systems (e.g. transformers, lines, phase shifters, busses) in significant detail. For example, it represents capacity constraints, minimum start up time limitations, and thermal constraints on the transfer capability of transmission lines, line and unit contingencies and scheduling limitations of hydro-plants. As such, GridView provides a detailed simulation of the hourly operation of the individual generating units and transmission system that constitute the wholesale market.

The GridView database was created from the Transmission Expansion Planning Policy Committee ("TEPPC") 2022 database as updated by the ISO and NV Energy. The TEPPC is a committee of the Western Electricity Coordinating Council ("WECC") that is responsible for the oversight and maintenance of a public database for production cost and related analysis. The TEPPC develops and implements planning processes to improve the economic analysis and modeling of the Western Interconnection. The TEPPC 2022 database incorporates load forecasts from each of the BAAs, existing and planned generation, transmission infrastructure, and expected generation retirements.

The ISO updated the TEPPC 2022 database to reflect the ISO's transmission expansion plan for compliance with California's renewable portfolio standard and reliability needs. The ISO also updated the TEPPC 2022 database to reflect the best available information on generation retirements, such as the San Onofre Nuclear Generating Station, and conventional and renewable generation additions.

The economic analysis incorporated assumptions on PacifiCorp's participation in the EIM including 400 MW of transfer capability between ISO and PacifiCorp systems via the California-Oregon transmission intertie.

Finally, NV Energy provided ABB and E3 with updates to better reflect the NV Energy system from the information in the TEPPC 2022 database. ABB and E3 used that data to model the business-as-usual case and the EIM change case.

B. Modeling Assumptions Used in the Economic Analysis

The ISO provided the following modeling inputs for the economic analysis:

- The fuel price forecast used in the economic analysis was from the ISO's 2021 transmission planning. NV Energy reviewed and approved the fuel forecast for each of the regions in the Western Interconnection.

- Generic resource additions to satisfy reliability requirements in the Los Angeles basin and San Diego load pockets.

- California greenhouse gas emissions allowance prices based on the Califrnoa Energy Commission forecast for compliance with the emissions targets under California Assembly Bill 32.

NV Energy provided the following modeling inputs to economic analysis:

- Updated the energy profiles of existing renewable purchase power agreements for consistency with NV Energy's planning assumptions in the 2013 Sierra Pacific Power Integrated Resource Plan.

- Updated the NV Energy reserve requirements for balancing variable energy resources, specifically solar and wind, consistent with those provided in the 2013 Sierra Pacific Power Integrated Resource Plan.

- Provided transmission capabilities in the form of WECC Path Ratings. These ratings exist for each of the Companies' paths into, and out of, the NV Energy BA. In cases where path ratings are limited by seasonal conditions like hydroelectric output, regional temperatures or fuel prices the seasonal limits, known as Operating Transfer Capabilities, were used.

- Confirmed transmission facility ratings for the study group for each Company transmission system element in the model. Expected ratings for new facilities were provided but because of limited transmission expansion planned prior to 2022, the only major change in ratings was the inclusion of the planned Harry Allen transformer in both the 2017 and 2022 cases.

ABB and E3 generated model outputs using GridView which were then used to calculate economic benefits. The model outputs included forecast energy prices, namely LMP. NV Energy reviewed the model outputs, including the following:

- Path flows,

- The average LMPs produced by the model,

- Total generation (Unit annual production for the entire West), and

- Total generation costs.

As a result of the parties' continued review of the initial results of the economic analysis, and to capture more recent developments as the modeling effort continued, the ISO and NV Energy modified additional generation and transmission input assumptions. The modified input assumptions included the following actions:

- Incorporated the decision to retire the San Onofre Nuclear Generating Station.

- Included changes to reflect the adoption of Nevada Senate Bill 123, including:

- Modeled retirement dates of Reid Gardner units 1, 2, and 3 by December 31, 2014, and modeled Reid Gardner Unit 4 retirement by December 31, 2017
- Addition of 350 MW of solar capacity.
- Addition of 550 MW of combined cycle gas capacity.

- Added the retirement of one 750 MW unit at the Navajo Generating Station as of December 31, 2019, as proposed by the joint owners to the Environmental Protection Agency to satisfy the requirements of the Clean Air Act.
- Transmission Topology - Based on a reconfiguration by the BAs around Eldorado, NV Energy gained ownership of two direct connections to ISO, with bidirectional capacity of approximately 1,500 MW between the ISO and NV Energy. This increased capacity was reflected in the subsequent modified assumptions.[3]
- Contract rights and capacities were modeled into hubs to ensure tariff charges were not applied to LMP calculations for the Company's transactions through adjacent BAs that were using NV Energy's existing transmission contract rights.

C. Economic Benefits

The final report prepared by E3 provides a range of potential economic benefits, with the low range reflecting a scenario in which assumptions were generally chosen to be conservative and a high range that used less conservative assumptions.

An expanded EIM that includes the Companies, in addition to the ISO and PacifiCorp, would allow participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources between the ISO, PacifiCorp and NV Energy systems, and thereby reduce production costs, flexibility reserves, and renewable generation curtailments. Specifically, the economic analysis concludes that participation of NV Energy in the EIM would yield the following three principal economic benefits:

- *Interregional dispatch savings* by realizing the efficiency of combined 5-minute dispatch and real-time unit commitment across the NV Energy, ISO and PacifiCorp BAAs. That would reduce "transactional friction" and alleviate structural impediments currently impacting trade on ties between the ISO and NV Energy BAAs;
- *Reduced flexibility reserve* by offsetting the three systems' load, wind, and solar variability and forecast errors; and

[3] The Economic Analysis did not adjust the post-EIM cases to reflect the removal of hurdle rates between NV Energy and PacifiCorp (see direct testimony of Mr. Whalen).

- *Reduced renewable energy curtailment* by allowing BAAs to export or reduce imports of renewable generation when they would otherwise need to curtail their own resources. During low load periods, BAs will have excess generation due to the must-take nature of renewable resources, rather than curtailing the resources that may be dispatched to serve other participating BAs' requirements.

These benefits are expected to reduce the Companies' energy production costs, with the cost savings accruing to customers.

Table 1 provides a summary of the estimated gross annual benefits to the EIM area (i.e., NV Energy, PacifiCorp, and the ISO) for the study years of 2017 and 2022. The study year 2017 was chosen because it represents a near-term time period after the ISO EIM will be in operation.

The study year 2022 represents a period when significant system changes will have been implemented, including: (1) full build-out of renewable resources to meet California's 33% Renewable Portfolio Standard target; (2) full expected retirement and/or replacement of ISO thermal generating capacity due to once-through-cooling ("OTC") regulations; (3) construction of a number of planned and proposed transmission projects,; and (4) projected higher CO2 permit prices in California as a result of full implementation of California's GHG statute and regulations. Projected benefits increase slightly in study year 2022 due to a higher dispatch and a higher flexibility reserve. Table 2 provides the estimated gross annual benefits to NV Energy.

Table 1. Estimated gross annual EIM benefits to EIM Area (million 2013$)

Benefit Category	2017		2022	
	Low range	High range	Low range	High range
Interregional dispatch	$6.2	$9.3	$8.9	$13.4
Flexibility reserves	$2.6	$5.0	$5.7	$12.0
Renewable curtailment	$0.4	$4.0	$0.4	$4.0
Total benefits	**$9.2**	**$18.2**	**$15.0**	**$29.4**

Note: Individual estimates may not sum to total benefits due to rounding.

Table 2. Estimated gross annual EIM benefits to NV Energy (million 2013$)

Benefit Category	2017		2022	
	Low range	High range	Low range	High range
Interregional dispatch	$3.1	$4.7	$4.5	$6.7
Flexibility reserves	$2.8	$3.6	$3.2	$4.3
Renewable curtailment	$0.1	$1.2	$0.1	$1.2
Total benefits	**$6.0**	**$9.5**	**$7.7**	**$12.2**

Note: Individual estimates may not sum to total benefits due to rounding.

Table 3 describes the assumptions used to develop the low range and high range of benefits. In the low range the assumption was made that NV Energy units would not participate during the summer peak period, rather such resources would only be utilized to serve NV Energy loads in that season. In the high range the units were assumed to be available year round and able to be dispatched as needed when NV Energy was not dispatching the units to meet its own load needs.

Table 3. Key assumptions in low and high range benefit scenarios

Assumption	Low range	High range
Availability of NV Energy generators to participate in EIM	Unavailable during June-Sept	Available in all months for EIM dispatch; full-year dispatch benefits used
Calculation of flexibilty reserve benefits	Quantity reduction in reserve requirement valued at benchmark of average ISO historical ancillary service market price levels	Simulation directly calculates benefits of reduced reserves, and improved efficiency through enabling optimal procurement of reserves from across the EIM footprint, subject to transmission constraints
Share of identified renewable energy curtailment value avoided in California	10%	100%

D. Estimated Cost of NV Energy Participation in the ISO EIM

NV Energy has developed an estimate of the costs it will incur to implement and participate in the ISO EIM by identifying known cost components such as the ISO start up fees, NV Energy's start-up costs, and ongoing costs. The major cost categories for the implementation and operation of the EIM include the following:

Capital Costs

- **Software Implementation:** System implementation and/or modifications are necessary related to resource and load systems, scheduling, generation imbalance, settlements, and interfaces, EMS real time network modeling, outage management and resource optimization.
- **Metering:** Select meter upgrades are necessary and it is anticipated that approximately 38 meters will be replaced.
- **Telecommunication:** Select telecommunication enhancements are anticipated.
- **Meter Data Management System:** Implementation of the software to transfer the meter data from the participating resources.
- **Implementation Fee:** The upfront fee paid to ISO to expand the ISO's network model to include NV Energy in the Energy Imbalance Market.

Operations and Maintenance Costs

- **Software Implementation:** The annual licensing fees associated with the implemented of modified software applications for the EIM.
- **Grid Operations:** The hiring of four new full time equivelant employees ("FTEs") to manage scheduling and real-time operations associated with the EIM.
- **Metering:** The costs associated with maintaining the meters.
- **Telecommunication:** The costs associated with maintaining incremental telecommunication facilities.
- **Meter Data Management System (MDMS):** The annual licensing fee associated with implementing the MDMS system. This also includes the hiring of one FTE to support the interface of the meter data for the EIM.
- **Merchant Settlement:** The hiring of two new FTEs to handle the market analysis and merchant settlements requirements associated with the EIM.
- **Transmission Settlement:** The cost of a FTE to allocate and invoice

transmission customers for tariffed transmission services.

- **Administration Fee:** The fee paid to ISO, annually, to participate in the EIM.

- **Transaction Fees:** The fees paid to the ISO, for each transaction, when participating in the EIM.

Estimates for metering and telecommunications were developed working with NV Energy technical staff and assessing the existing infrastructure to determine what facilities will need to be upgraded or replaced. The cost to integrate the computer systems was determined by working directly with the ISO and PacifiCorp staff on the implementation concepts, while customizing the system interface information specific to NV Energy. NV Energy's initial estimated costs to implement the EIM are shown in Table 4, which summarizes the major work stream items and the upfront capital costs and ongoing O&M costs. The budget shown in Table 4 includes the upfront implementation fee to be paid to the ISO of $1.1 million along with estimates for ongoing transactional fees.

In addition, Table 4 illustrates the cost necessary to upgrade metering and telecommunication at some of the NV Energy generation units and also includes the estimates to upgrade the scheduling, trading, and settlement computer systems required to operate in the EIM.

Contained in the O&M budget is the estimated increase of eight FTEs necessary to carry out the functions of participation in the EIM and to maintain the system. Of the eight budgeted FTEs, four are to support real-time grid operations performing transmission scheduling, monitoring and operation coordination functions; one is to support incremental meter data management; one is to perform merchant ISO market analysis; one for merchant ISO settlement validation; and one to support transmission settlement billing and validation.

Because the EIM is a new market, there is some level of uncertainty about staffing requirements. NV Energy's transmission and merchant function will re-evaluate staffing needs following the October 2014 go-live of the EIM with the additional benefit of PacifiCorp's experience with post-EIM market operations. This may require the addition of up to four additional FTEs depending on how the implementation impacts existing merchant operations. It is estimated the four incremental FTEs could cost approximately $600 thousand per year. These additional costs are not included in the O&M total in Table 4.

Table 4 – NV Energy Estimated Costs to Implement and Operate the EIM (w/o AFUDC)[4]

Capital	1	Software Modification/Implementation	$ 2,150,000
	2	Metering	$ 547,592
	3	Telecommunications	$ 1,038,000
	4	Meter Data Management	$ 287,959
	5	Project Support	$ 3,350,000
	6	Loadings	$ 427,666
	7	Contingency (30 percent)	$ 2,340,365
Capital Subtotal			$10,141,582
	8	Implementation Fee	$ 1,100,000
Capital Total			$11,241,582
O&M	1	Software Modification/Implementation	$ 261,000
	2	Grid Operations	$ 600,000
	3	Metering	$ 6,125
	4	Telecommunications	$ 15,000
	5	Meter Data Management	$ 157,513
	6	Merchant Settlement/Market Montioring	$ 300,000
	7	Transmission Settlements	$ 150,000
	8	Administration Fees	$ 706,040
	9	Transaction Fees	$ 55,884
	10	Loadings	$ 130,591
	11	Contingency (10 percent)	$ 238,215
O&M Total			$ 2,620,368

E. Net Economic Benefits

The Economic Analysis was conducted using the ISO data set for years 2017 and 2022. As part of the Economic Analysis, E3 calculated an estimated 20-year net present value ("NPV") by assuming an increasing level of benefits would occur throughout the 20-year study period. This estimate was based on a linear interpolation of 2017 and 2022 data and then a conservative 2% inflation rate from 2022 through 2035. The NPV captured the benefits and costs starting in 2016. Netting out the capital and ongoing costs, the 20-year NPV benefit to NV Energy customers is estimated to be between $40.3 million and $87.6 million.

The estimated revenue requirement necessary for the Companies to recover the capital and ongoing O&M costs for participation in the EIM is $4.4 million in 2017 and $4.1 million in 2022. Comparing this to the annual range of economic benefits shown in

4 The Initial Study costs have not been included in this cost estimate because these costs have already been incurred and so are not properly part of this ESP amendment. The companies anticipate that the Study costs will be presented to the commission in the 2016 Sierra general rate case and the 2017 Nevada Power general rate case.

Table 1 for 2017 of $6.0 to $9.5 million yields an annual net benefit to NV Energy customers of $1.6 to $5.1 million in 2017. Comparing the range of economic benefits shown in Table 1 for 2022 of $7.7 and $12.2 million to the annual revenue requirement yields an overall annual net benefit to NV Energy's customers of $3.6 to $8.1 million in 2022.

SECTION 5 – RELIABILITY BENEFITS

NV Energy's participation in the ISO EIM is expected to produce reliability benefits in addition to the economic benefits discussed above. These reliability benefits generally fall into two broad categories: 1) improved management of imbalances, and transmission constraints, 2) enhanced situational awareness. Reliability benefits were not quantified for the economic analysis.

A. Improved Management of Imbalances

The ISO EIM will deliver a mechanism to effectively aggregate the resource to load imbalances of the participating BAs and provide a dispatch solution relative to transmission capacity from a wider suite of available resources than would be available if each BA were to manage imbalances independently. For instance, where one BA encounters a negative imbalance (under-generating) the EIM dispatch option includes not only the resources within that BAAs, but also resources from the other participating BAAs from which an economic dispatch solution can be achieved. The dispatched generation will be governed by real-time and anticipated transmission flows based on the state estimator model. This makes more resources available to react to imbalances, thereby not only improving reaction time and performance, but doing so in a way that does not negatively impact transmission limits while achieving superior efficiency.

In the event that two BAs have imbalances of opposite signs (i.e. one over-generating and the other under-generating) to the extent that the resources have been dispatched economically at the outset, the EIM solution will tend to establish interchange between the two BAs in order to resolve the imbalance. In such a situation, the generating resources need not be re-dispatched at all, thus resulting in reduced ramping of the generating resources in both BAs and lower wear-and-tear on the equipment. This concept also diversifies variable generation fluctuation across geographic regions.

B. Enhanced Situational Awareness

Lack of situational awareness of operating personnel has been a key factor in a number of recent electric system disturbances, most notably the August 2003 blackout in the Eastern Interconnection. The September 2011 disturbance affecting large portions of Southern California also served to underscore the importance of situational awareness in the West. The EIM will improve situational awareness in at least two ways: first by enhancing the modeling and visibility of the combined footprint of the participating BAs, and second by more accurately predicting the loads and resources in a shorter time increment than is done in the current paradigm.

In the present hourly dispatch approach, the determination of forecast load and unit commitment is made before the operating hour. Given the myriad of unknowns and uncertainties, not the least of which is the production levels of renewable resources, such an approach invariably leads to mismatches and imbalances going into the hour. This requires manual operator intervention to correct the imbalance. By contrast, the EIM makes forecast and commitment determinations on a five-minute basis. The shorter time horizon results in reductions in mismatches between loads and resources.

As a result of incorporating the EIM area into the ISO network model, the operational tools that the ISO uses within the existing market area become available to the entire EIM area. Using already-implemented operations tools, the ISO performs real-time stability analyses that necessarily consider the entire Western Electricity Coordinating Council region, and observes voltages and other conditions outside the existing market footprint, to identify conditions that may have impacts on the market area that may need to be managed.

The EIM will complement NV Energy's reliability functions by providing additional situational awareness of neighboring areas as well as the market footprint. The optimization of the 5-minute dispatch will be performed using a security constrained economic dispatch model that enforces flow based limits in the market footprint thus enhancing reliability within the market footprint. This reduces the potential impact on neighboring systems, enhances situational awareness and enhances reliability for the entire Western Electricity Coordinating Council ("WECC") region. This allows operators' decisions to be as informed as possible about pertinent system conditions as well as achieve cost savings in scheduling of resources.

The reliability benefits the EIM will produce are highlighted in two recent reports issued by staff of the North American Electric Reliability Corporation ("NERC") and FERC. In response to the September 2011 Southern California outage, FERC and NERC Staff issued a report entitled "Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations." [5] That report makes several recommendations for increasing situational awareness in the WECC region, including: (1) expanding entities' external visibility in their models through more complete data sharing; (2) improving the use of real-time tools to ensure the constant monitoring of potential internal or external contingencies that could affect reliable operations; and (3) improving communications among entities to help maintain situational awareness.

In a February 2013 report,[6] FERC Staff found that an EIM could provide reliability benefits through (1) security constrained economic dispatch for better management of imbalances and enhanced ability to manage flows within system operating limits, (2) enhanced situational awareness, (3) potentially fewer energy emergency alerts, (4) faster

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[5] See "Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations," April, 2012. Available at https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

[6] "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," February 26, 2013. Available at: http://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

dispatch and delivery of replacement generation after contingency reserve sharing assistance ends and for contingencies beyond reserve obligations, and (5) assisting with the integration of diverse conventional and emerging technologies including variable energy resources and demand response.

SECTION 6 – IMPLEMENTATION OF THE EIM

If the Commission approves this Joint Application, the Companies expect to participate in the EIM starting in October 2015. The ISO allows entities to enter the EIM once a year in October. Implementation requires approximately 18 months.

In cooperation with ISO, NV Energy has developed discrete work streams, a comprehensive project schedule, and has established a project implementation team with executive leadership oversight. Consistent with the cost estimate presented above, NV Energy will take the following actions to participate in the EIM:

- Coordinate with the ISO on the Full Network Model expansion for NV Energy
- Install new software systems
- Install new metering and telecommunications equipment
- Test the new systems
- Train Company staff
- Obtain regulatory approvals
- Conduct Market Simulation
- System Deployment and Go Live

In order to achieve the implementation schedule, the ISO and NV Energy have executed the Implementation Agreement. The Implementation Agreement provides the scope of work to be accomplished between the parties and sets forth specific milestone payments to be delivered to the ISO as the implementation progresses. By June 1, 2014, NV Energy and the ISO will develop and initiate a final project management plan that describes specific project tasks each Party must perform, delivery dates, project team members, meeting requirements, and a process for approving changes to support completion of the Project.

The Implementation Agreement is contained in the Technical Appendix as Item 2. NV Energy has created an implementation team to carry the project through completion. The team is led by senior management in an executive steering role with a leadership team focused on implementation and delivery as well as strategy and outreach. The specific milestones contained in the Implementation Agreement are summarized below:

- Milestone 1 – Agreement made effective.
    - Upon approval of FERC and the Commission
    - Estimated to be August 27, 2014
    - Payment to the ISO $300,000

- Milestone 2 - This milestone is completed upon modeling NV Energy into the ISO Full Network Model through the EMS which will be deployed into production using the ISO's network and resource modeling process.
    - January 28, 2015
    - Payment to the ISO $200,000

- Milestone 3 - ISO to promote market network model including NV Energy area to non-production system and allow NV Energy to connect and exchange data in advance of market simulation.
    - May 15, 2015
    - Payment to the ISO $200,000

- Milestone 4 - The EIM market simulation will allow NV Energy and the ISO to conduct specific market scenarios in a test environment prior to the production deployment to ensure that all system interfaces are functioning as expected and to produce simulated market results. To complete this milestone, the commencement of EIM simulation will signal that NV Energy and the ISO have independently completed EIM system design, development, and testing to participate in joint testing.
    - August 10, 2015
    - Payment to the ISO $200,000

- Milestone 5 – This milestone is complete upon the first production NV Energy EIM trade date.
    - October 1, 2015
    - Payment to the ISO $200,000

SECTION 7 – EIM GOVERNANCE

The expansion of the ISO EIM outside of its BAA has caused interested parties in the West to press for a change in governance that would give EIM participants and other regional interests a voice in EIM decision-making, as well as propose a long-term independent governance structure.

In response, the ISO conducted a stakeholder process to develop a proposal to broaden participation in EIM decision-making. The proposal, which was approved by the ISO Board in December 2013, outlines steps to develop meaningful changes in governance, starting with the formation of a transitional EIM stakeholder committee (the "Transitional Committee"). NV Energy participated in the stakeholder process that will result in the transitional committee. It is also important to note that NV Energy has a guaranteed seat on the Transitional Committee, which NV Energy will utilize to support the development of good operational and governance policies. Finally, the EIM will have been operation for a year, and the transitional committee in place for almost 18 months when NV Energy begins to participate in the EIM.

A. Transitional Committee Structure

The Transitional Committee will be composed of members nominated by a broad cross-section of EIM stakeholders from different sectors. Three of the seats are designated for EIM Entities that have signed Implementation Agreements with the ISO. By signing the Implementation Agreement now, NV Energy will be a member of the Transitional Committee. PacifiCorp, which has already signed an implementation agreement, is also guaranteed a seat on the Transitional Committee. The intent is to have a Transitional Committee that is composed of a diverse group of participants. It will be formed through open stakeholder processes of which the Companies were a part. A final selection of committee members will be completed in May.

B. Operation of the Transitional Committee

The Transitional Committee will be established in late May 2014. It will serve as an advisory committee to the ISO Board and will offer comments to the ISO Board and Management on matters related to EIM implementation. In addition, the Transitional Committee will be tasked over the subsequent 12-18 months with developing a recommendation for establishing an independent EIM governance structure including defined authority over EIM matters.

The Transitional Committee meetings and deliberations will be subject to ISO open meeting policies and notice requirements. Its work will result in a proposal (or possibly multiple proposals) for consideration by the ISO Board. Implementation of the proposal(s) will require ISO Board approval and FERC approval of any needed tariff changes.

An ISO staff person will perform a liaison function for the committee, attend committee meetings, and facilitate the provision of ISO support to the committee. This will ensure that the Transitional Committee has the benefit of extensive market design expertise and that it is informed regarding, and can accomplish its goals in conjunction with, the existing ISO governance and management structures.

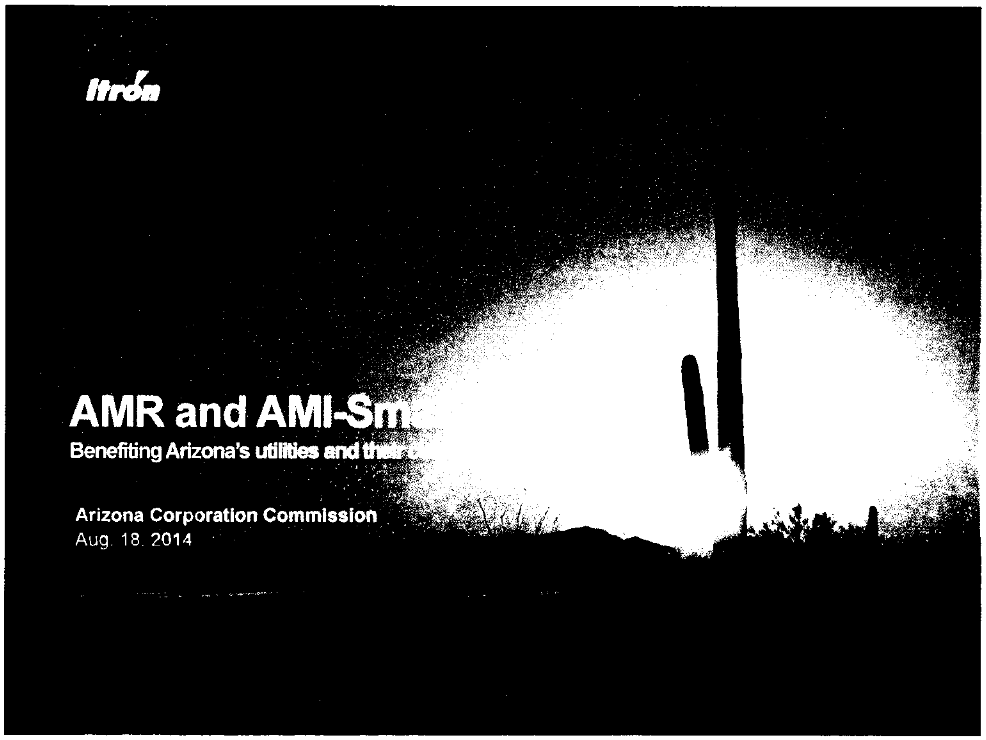
SECTION 8 – AMENDMENT OF THE COMPANIES' RESPECTIVE ENERGY SUPPLY PLANS

The Companies propose to amend their respect Energy Supply Plans as follows:

(1) Section IV.A.5 ("Current Portfolio Optimization Procedures") of the Nevada Power Energy Supply Plan approved in Docket No. 12-06053 as updated in Docket No. 13-08024 attached in the appendix as Item 3; and

(2) Section IV.A.4 ("Current Portfolio Optimization Procedures") of the Sierra Pacific Energy Supply Plan approved in Docket No. 13-07005 attached in the appendix as Item 4.

The amendment to the Current Portfolio Optimization Strategy of each Company's Energy Supply Plan adds the Companies' participation in the ISO EIM. Participation in the EIM further optimizes the Companies' energy supply portfolios for the benefit of their customers.



ITRON

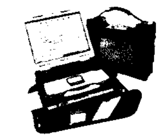
- www.itron.com
- Provide metering, meter reading, data management, products and services to the utility industry – Electric, Water, Gas, Solar
- Customers in Arizona include APS, SRP, TEP, UniSource, Southwest Gas, Cities of Phoenix and Tucson, and many more.
- Jeff Rowe – jeff.rowe@itron.com, (602)870-3540

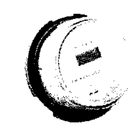
AGENDA

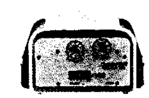
- AMR – Automated Meter Reading
- AMI – Advanced Metering Infrastructure
- SG – Smart Grid

WHAT IS AMR?

- One-way communications from meter to the data collection device – (hand-held computer, mobile computer, fixed data collectors)
- Benefits to the utility include:
  - Reduced meter reading operations expense
  - Improved meter reading accuracy
  - Improved meter reader safety
  - Diversion detection, Outage and restoration management
- Benefits for the customer:
  - Fewer visits to the home by the meter reader (privacy)
- AMR has been a proven technology for utilities in North America for 20+ years
  - Largest AMR systems in AZ are Tucson Electric, Southwest Gas, City of Phoenix.


MC3 Mobile Collection Unit


CENTRON C1SR Electricity Meter

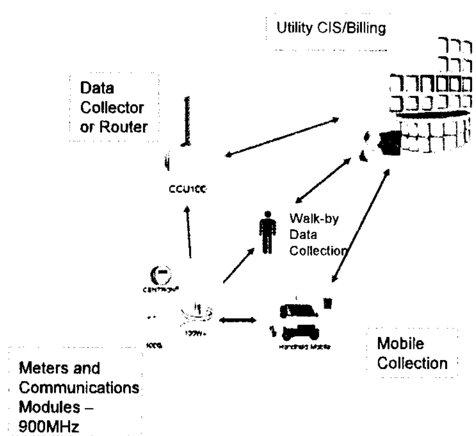

100G DLN ERT Module


CCU 100


FC300 Handheld Computer

AMR ARCHITECTURE

- Meter communications at 900 MHz, unlicensed RF.
- Communications are one-way, meter to collection device.
- E/W/G meters are read via –
  - Meter reader walking and collecting reads from the curb
  - Meter reader driving and collecting reads from the vehicle
  - Fixed data collectors
- Meter reads are delivered to the utility CIS/Billing system.



THE MOVE BEYOND AMR

Advanced Metering Infrastructure

AMI

Key Functionality

- AMR technology was not meeting the requirements or the business needs of the utilities - ~2005
- Key requirements
  - 2-way communications – control, command
  - Remote disconnect/re-connect
  - In-home communications, Demand Response
  - Support dynamic, time-based rates
  - Pre-payment
  - Upgradable over the communications network
  - Self-healing
  - Outage/restoration management
  - 20-year life of meter and system

INDUSTRY FORCES AND TRENDS

Driving these requirements

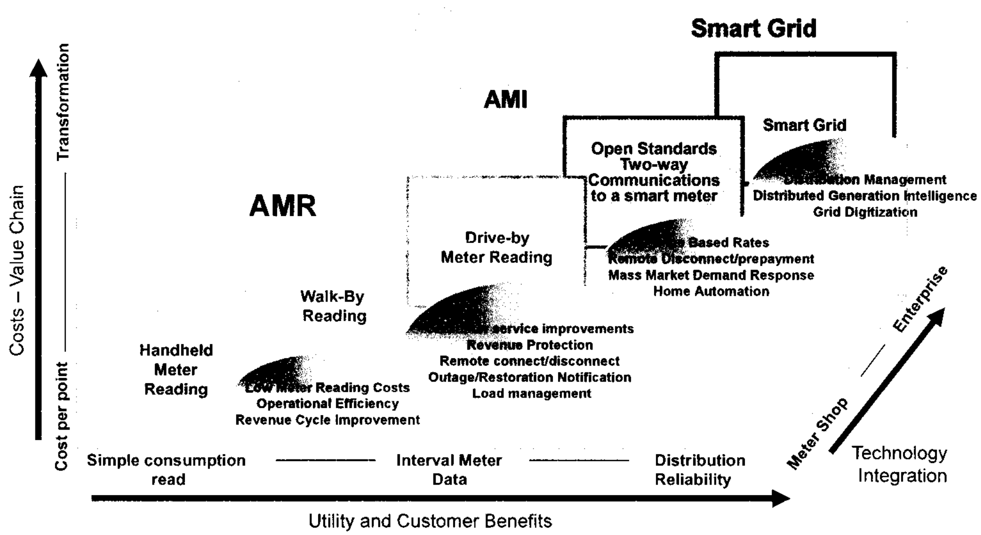
Industry Forces

- Increased pressure on operational efficiency and workforce productivity
- Increased focus on revenue assurance – elimination of theft
- Climate change and environmental concerns
- Growth in renewable generation and distributed resources
- Aging asset performance with increased expectations on reliability
- Increasing desire by consumers for a role in energy management and conservation

Industry Trends

- Sustainability – ensuring lasting resources for global water and energy
- Smart Cities
- Edge Data and Analytics
- Electrification of Transport – Electric Vehicles
- Cyber security intensity
- Customer Service and Growing Consumer Expectations

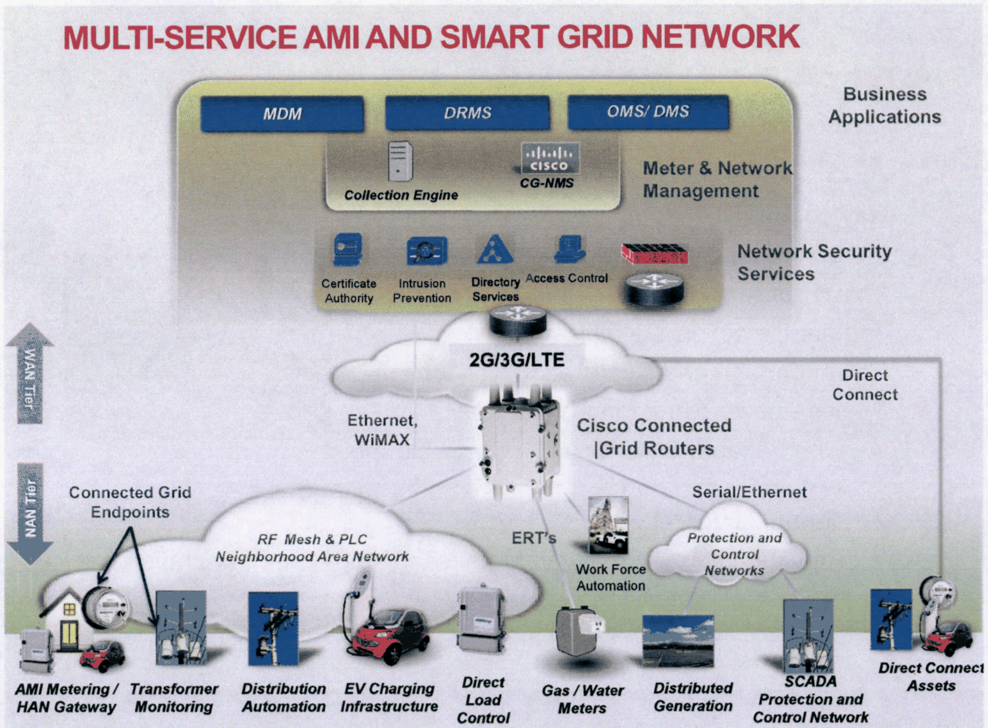
AMR TO AMI/SG – EVOLUTION OF METER READING



AMI AND SMART GRID

What is a Smart Meter?

- Consists of metrology, register board, communication board (two-way communications)
- Integrated disconnect/reconnect switch
- Load Profiling, Demand, Time-based rates
- Tamper Detection & Notification
- Power Outage and Restoration Notification
- Power Quality Monitoring (voltage)
  - Line Voltage, Blink Count, Outage Count
  - Voltage monitoring Captures min/max voltage values for each demand interval
  - Provides alarms for any value exceeding defined threshold
- Home Area communications, or HAN



AMI AND SMART GRID

Important keys to a Smart Grid

- AMR technology was not meeting the requirements or the business needs of the utilities - ~2005
- Key requirements
  - 2-way communications – control, command
  - Remote disconnect/re-connect
  - In-home communications, Demand Response
  - Support dynamic, time-based rates
  - Pre-payment
  - Upgradable over the communications network
  - Self-healing
  - Outage/restoration management
  - 20-year life of meter and system
  - Power quality
  - Standards-based – IPv6
  - Multi-service (AMI, Distribution Automation)
  - Technology ecosystem that supports partnerships and innovation
  - Management of distributed generation and electric vehicles – IES
  - Data Analytics

IMPORTANT UTILITY USE-CASES

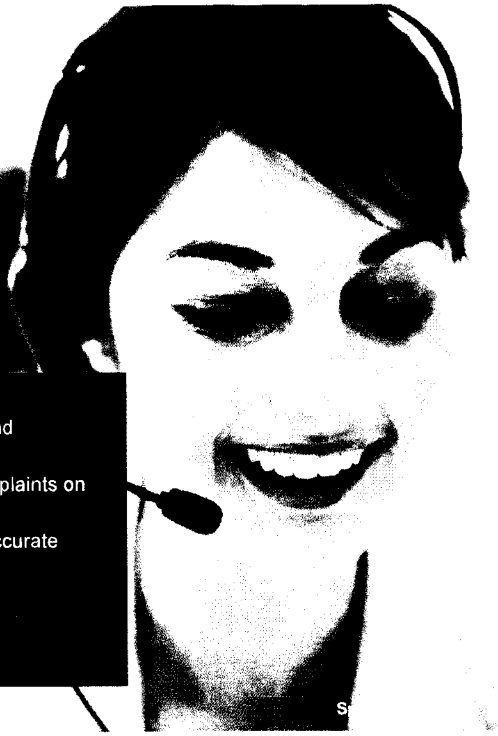
How is this technology being used?

DATA COLLECTION

AMI

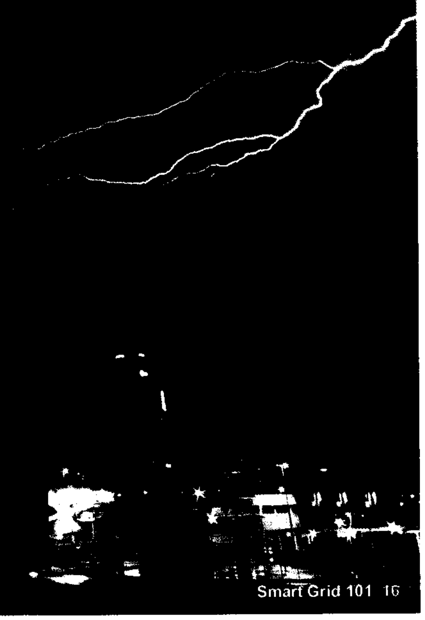
- Improve measurement and billing accuracy
- Reduce meter reading costs
- Increase worker safety and reduce environmental impact
- Customer privacy
- Provide insight into electrical service delivery at the service point

CUSTOMER SERVICE



- Automate customer service transactions and eliminate field visits
- Resolve customer billing inquiries and complaints on first call
- Empower CSRs with real time access to accurate meter data

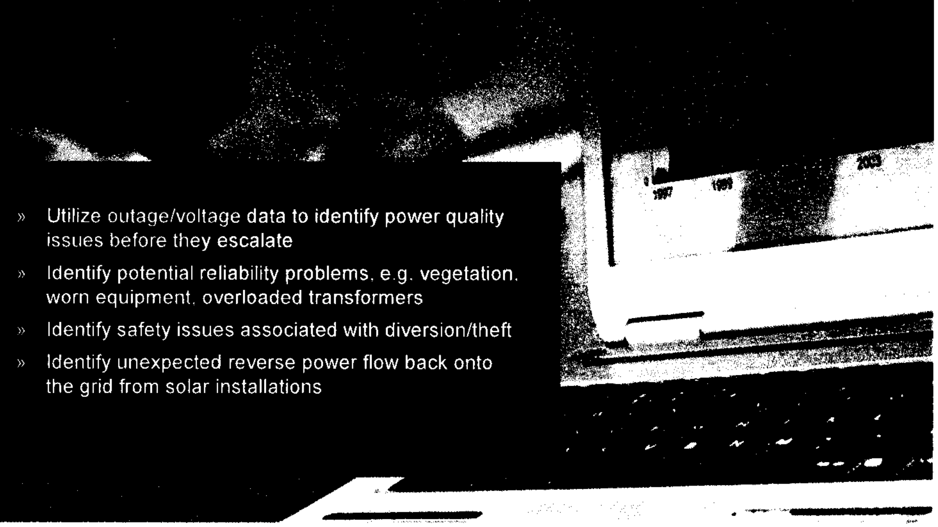
OUTAGE DETECTION & RESTORATION



- Improve reliability metrics (SAIDI/CAIDI/SAIFI) by detecting, responding & restoring faster
- Ensure outage data accuracy for large-scale and nested outages with voltage data, analytics
- Improve CSR and Field Service crew performance with direct access to AMI data

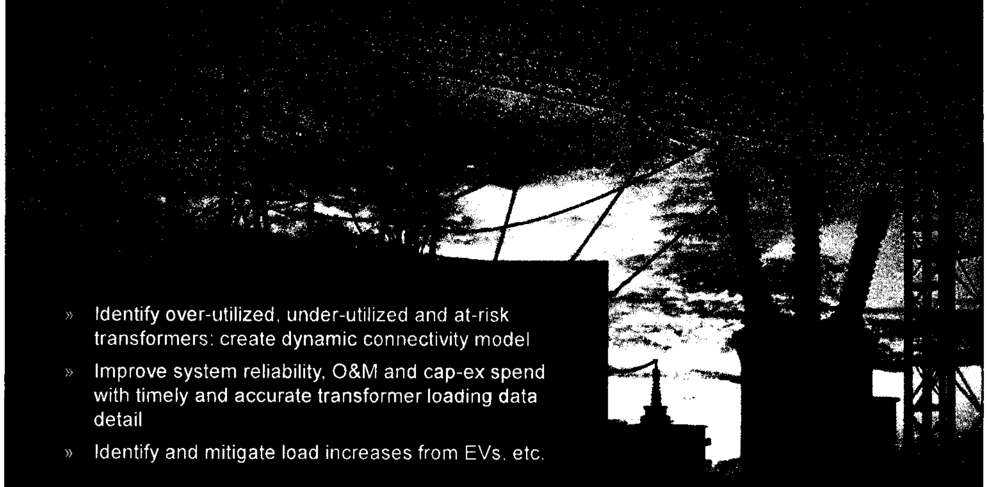
PREVENTIVE ANALYSIS

PQ (voltage), Asset Protection, Theft Detection, Distributed Generation

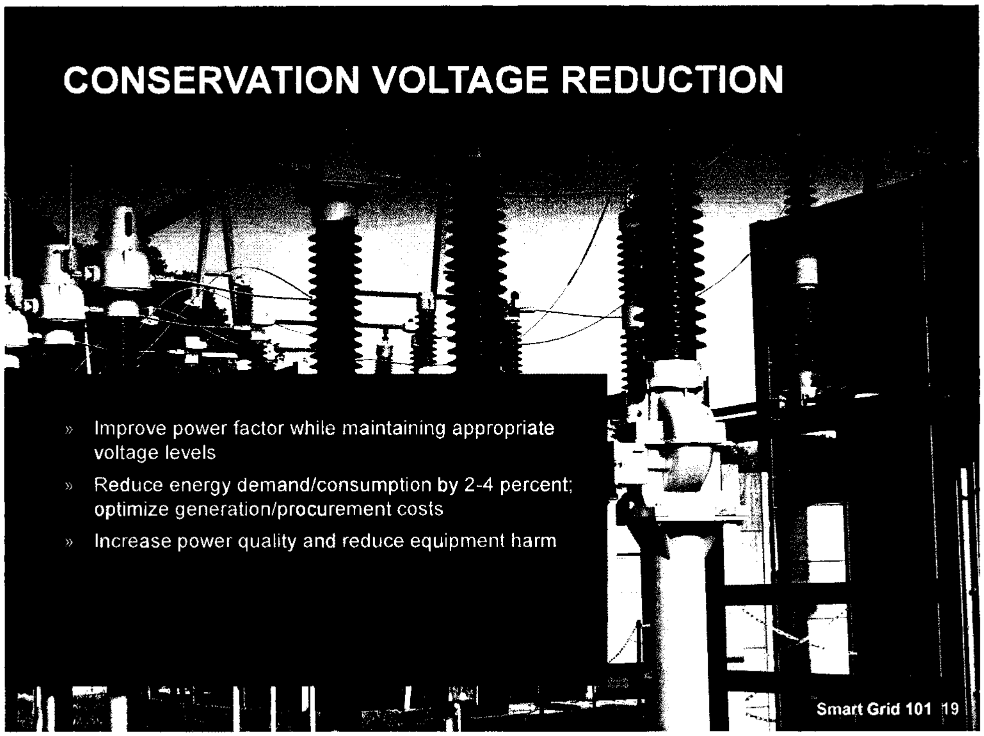


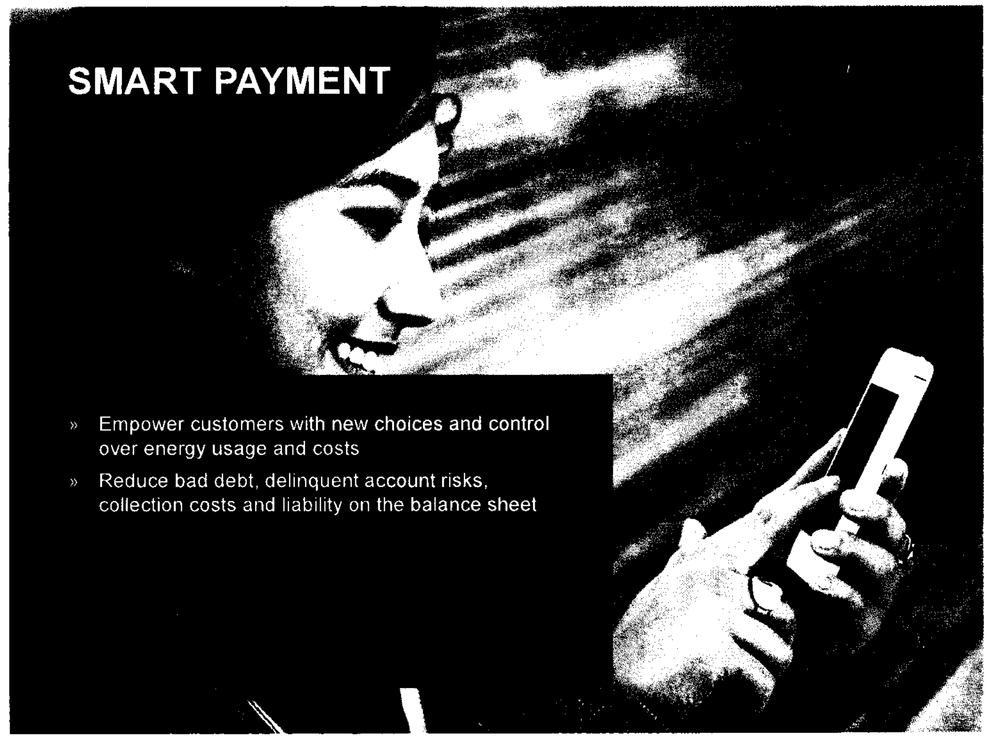
- Utilize outage/voltage data to identify power quality issues before they escalate
- Identify potential reliability problems, e.g. vegetation, worn equipment, overloaded transformers
- Identify safety issues associated with diversion/theft
- Identify unexpected reverse power flow back onto the grid from solar installations

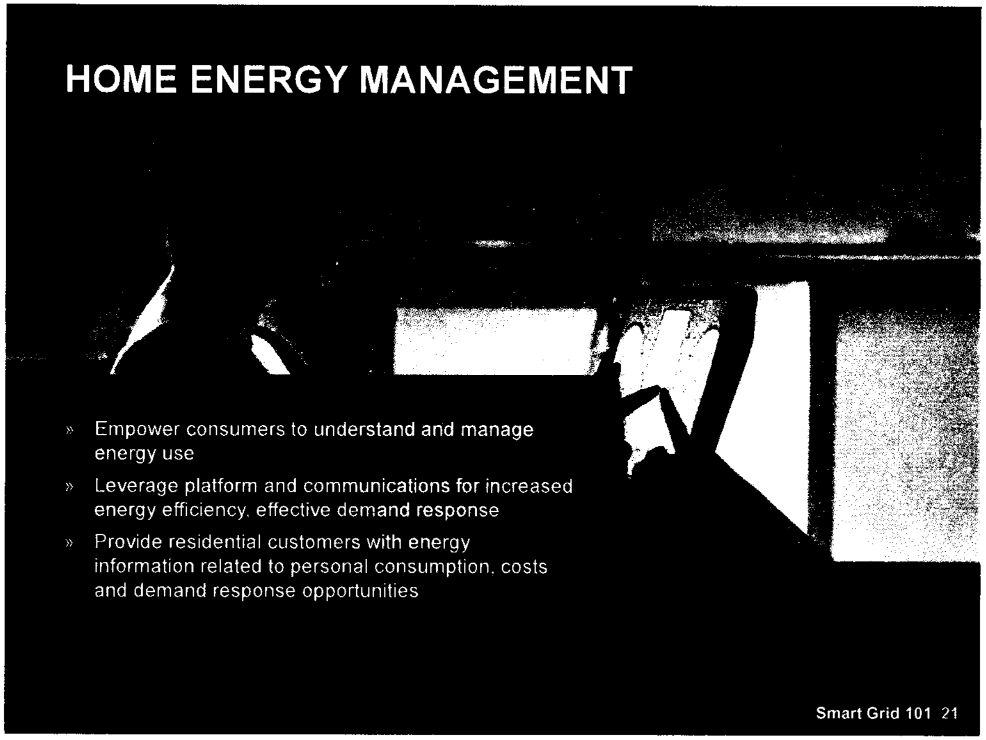
TRANSFORMER LOAD MANAGEMENT

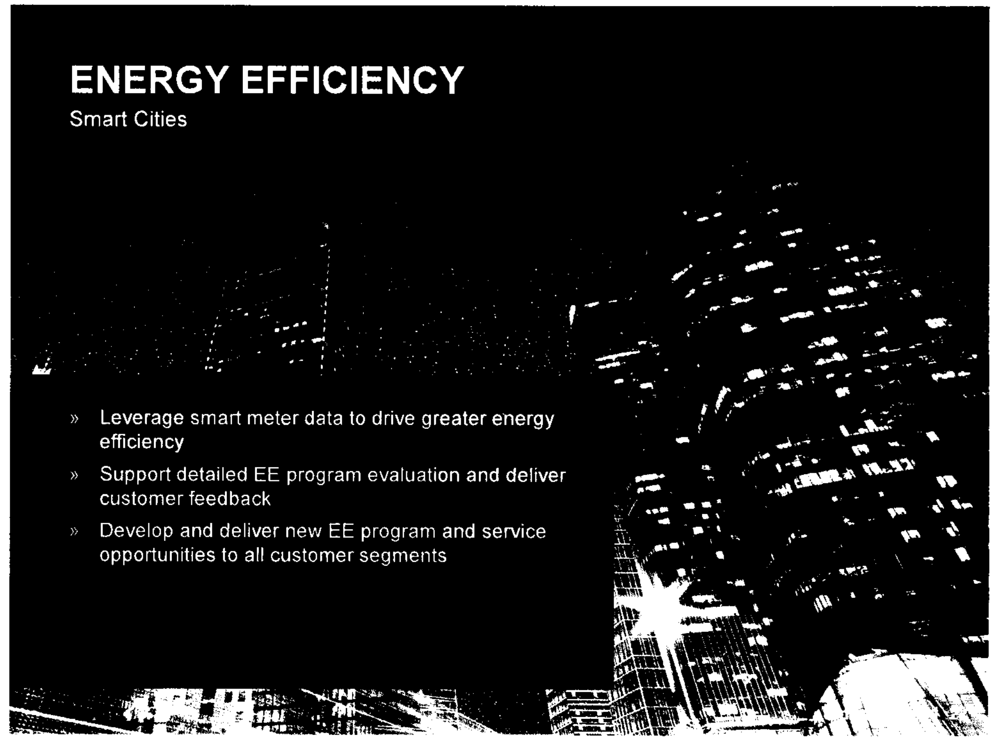


- Identify over-utilized, under-utilized and at-risk transformers: create dynamic connectivity model
- Improve system reliability, O&M and cap-ex spend with timely and accurate transformer loading data detail
- Identify and mitigate load increases from EVs, etc.


CONSERVATION VOLTAGE REDUCTION
» Improve power factor while maintaining appropriate voltage levels
» Reduce energy demand/consumption by 2-4 percent; optimize generation/procurement costs
» Increase power quality and reduce equipment harm
Smart Grid 101 19


SMART PAYMENT
» Empower customers with new choices and control over energy usage and costs
» Reduce bad debt, delinquent account risks, collection costs and liability on the balance sheet


HOME ENERGY MANAGEMENT
» Empower consumers to understand and manage energy use
» Leverage platform and communications for increased energy efficiency, effective demand response
» Provide residential customers with energy information related to personal consumption, costs and demand response opportunities
Smart Grid 101 21


ENERGY EFFICIENCY
Smart Cities
» Leverage smart meter data to drive greater energy efficiency
» Support detailed EE program evaluation and deliver customer feedback
» Develop and deliver new EE program and service opportunities to all customer segments

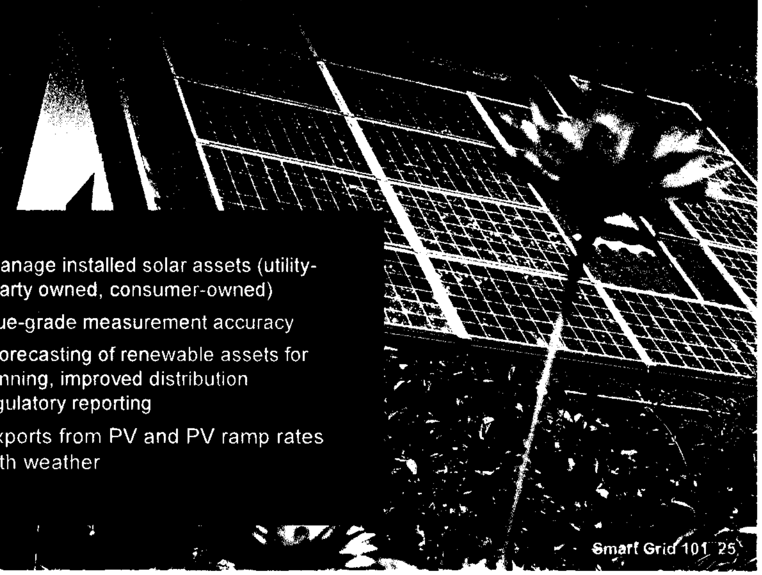
DEMAND RESPONSE

- Shave or shift peak load to address capacity and system congestion issues
- Mitigate demand impacts of EVs and renewable resources
- Mitigate market price volatility
- Support detailed program/pilot evaluation and customer feedback

REVENUE PROTECTION

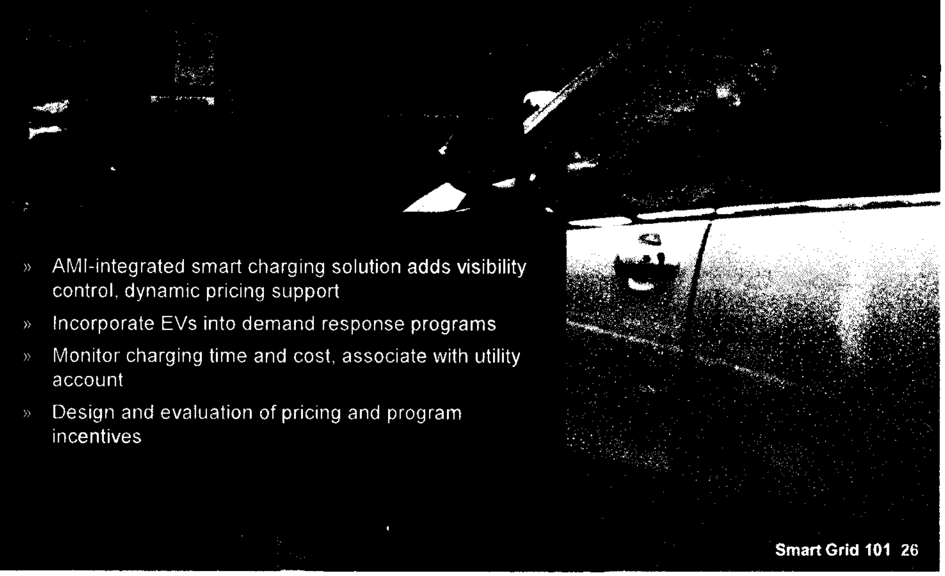
- Identify energy and revenue losses across distribution grid, from feeder to meter
- Utilize AMI data and other sources to pinpoint theft, target investigation resources
- Reduce unbilled energy consumption

SOLAR MONITORING
IES – Itron Embedded Sensing



- Monitor and manage installed solar assets (utility-owned, third-party owned, consumer-owned)
- Provide revenue-grade measurement accuracy
- Improve load forecasting of renewable assets for generation planning, improved distribution operations, regulatory reporting
- Identify net exports from PV and PV ramp rates associated with weather

EV SMART CHARGING
IES



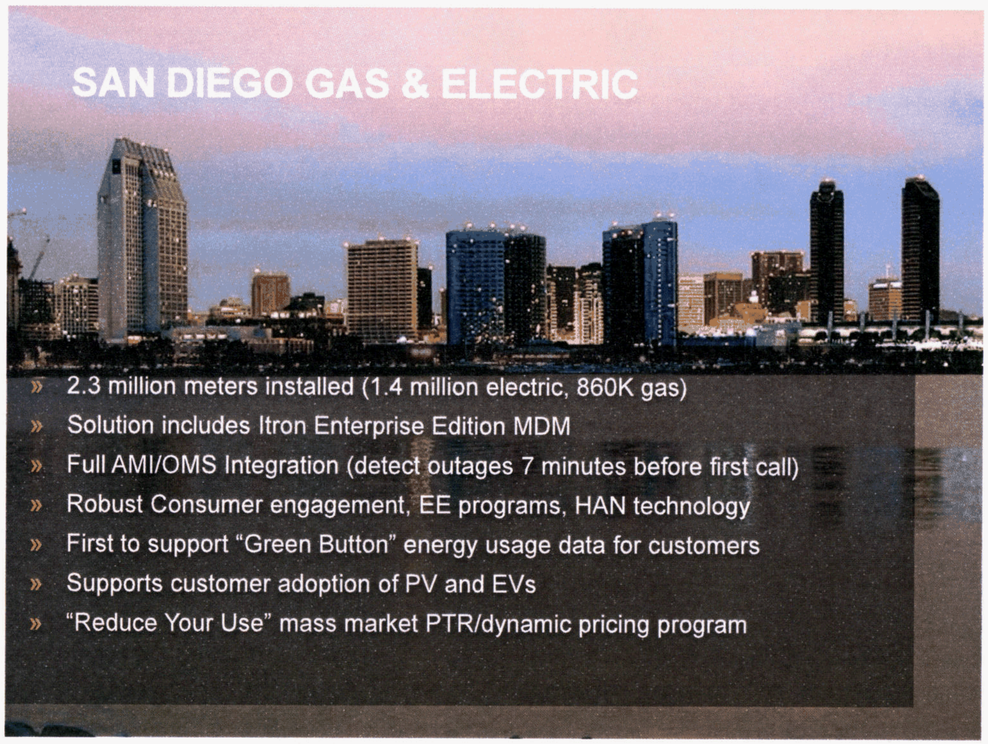
- AMI-integrated smart charging solution adds visibility control, dynamic pricing support
- Incorporate EVs into demand response programs
- Monitor charging time and cost, associate with utility account
- Design and evaluation of pricing and program incentives

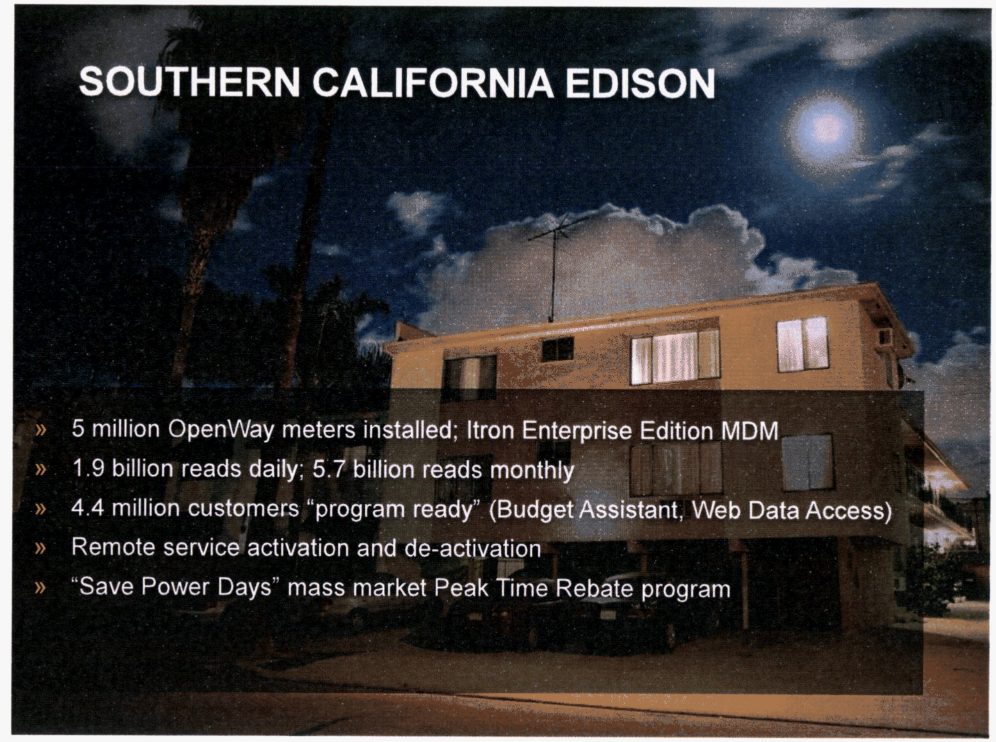
PROJECTS IN THE FIELD

Some of the major deployments in NA

CENTERPOINT ENERGY

- 2.3 million OpenWay meters installed
- 15-minute data from every meter
- Retailer support a key requirement in deregulated market
- Systems supports: dynamic rates, prepayment, IHDs/PSTs, DR, EE
- Avoided > 7 million vehicle trips to field
- AMS-OMS Integration: no more reliance on customer calls for outages
- Understand scope of outage in 2 minutes, not 15-45 minutes
- Dispatch time for restoration crews reduced from 14 to 6 minutes


SAN DIEGO GAS & ELECTRIC
» 2.3 million meters installed (1.4 million electric, 860K gas)
» Solution includes Itron Enterprise Edition MDM
» Full AMI/OMS Integration (detect outages 7 minutes before first call)
» Robust Consumer engagement, EE programs, HAN technology
» First to support "Green Button" energy usage data for customers
» Supports customer adoption of PV and EVs
» "Reduce Your Use" mass market PTR/dynamic pricing program


SOUTHERN CALIFORNIA EDISON
» 5 million OpenWay meters installed; Itron Enterprise Edition MDM
» 1.9 billion reads daily; 5.7 billion reads monthly
» 4.4 million customers "program ready" (Budget Assistant, Web Data Access)
» Remote service activation and de-activation
» "Save Power Days" mass market Peak Time Rebate program

BC HYDRO

- 1.9M electric meters installed in 2-year period
- Solution includes Itron Enterprise Edition MDM
- Full Itron-Cisco IPv6 network architecture
- Business case built on operational/distribution benefit and theft detection
- Leveraging Smart Meter as advanced Smart Grid sensor (voltage monitoring, transformer-level metering, dynamic connectivity)

OTHER MAJOR DEPLOYMENTS

» First Energy
» Duke Energy
» Detroit Edison
» National Grid
» Los Angeles Department of Water and Power
» Texas-New Mexico Power
» Consumer's Energy
» International market developing

THANK YOU

Itron

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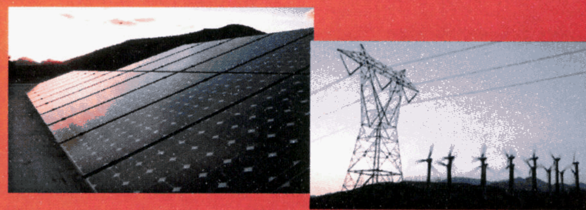


Emerging Technologies in Arizona:
The Projected Economics of an Energy Independent Community

Lon Huber

Residential Utility Consumer Office (RUCO)

The Scenario

2

- **Scenario A:** New 100 home community with centralized storage and rooftop solar
- **Scenario B:** New 100 home community with centralized storage and rooftop solar with natural gas backup
- **Scenario C:** New 100 home community with centralized storage and rooftop solar that is connected to the grid
- **Scenario D:** New 100 home community with centralized storage, rooftop solar, and geothermal HP
- **Scenario E:** One new home in existing neighborhood with local storage and rooftop solar

Goal of Exercise

3

- High level (ballpark) overview of costs
  - Non-academic in nature
- Based on assumptions and projections that will be wrong but represent the best guess for today
- Starting point to properly price micro grids
- Does not examine legal issues

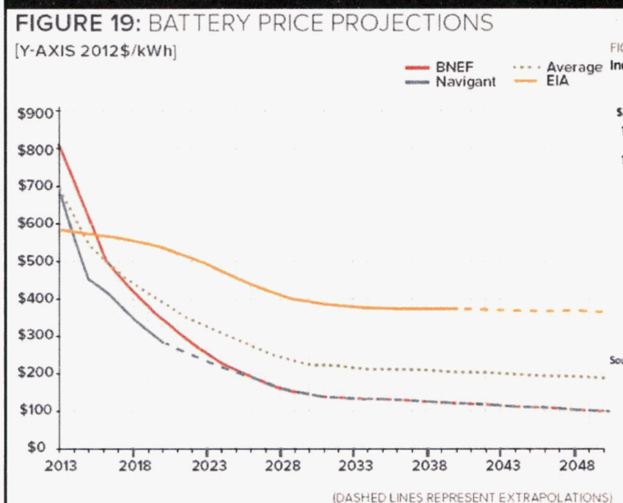
Assumptions - 2015

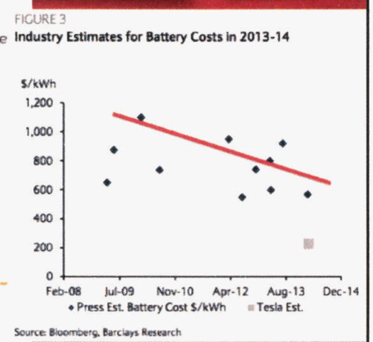
4

Time Frame	25 years	PV efficiency increase per yr.	0.65%
Days of Autonomy (max day)	2	PV price drop per year	2%
Days to Charge (min day)	3	Battery price drops per year	7%
Yearly Consumption	10,000 kWh	Yearly Average Peak Demand	4 kW
Year 1 Solar Production	1,850 kWh/kW	Grid cost increase per year	3%
Yearly Degradation	0.50%	Starting Year	2015
PV O&M	$3,781	Time value of money rate	3%
All-in Battery Cost ($/kWH)	$600.00	Starting Grid Cost	$0.13 kWh
Battery Tax Credit	20%	Price of NG service	$6.94/mmBtu
System Efficiency	75%	Geothermal cost per ton	$8,000
Battery Cycle Life	5,000	Fuel price for natural gas	$0.098 kWh
Battery Cycle/Day	1.0	O&M for natural gas	$0.03 kWh
PV Cost ($/W)	$3.00	No cost for C02	
PV Tax Credit	30%	Same tax credits as today	
Price floors for PV and storage	$1.50/$200	No preference on orientation of home	

Battery Price Projections

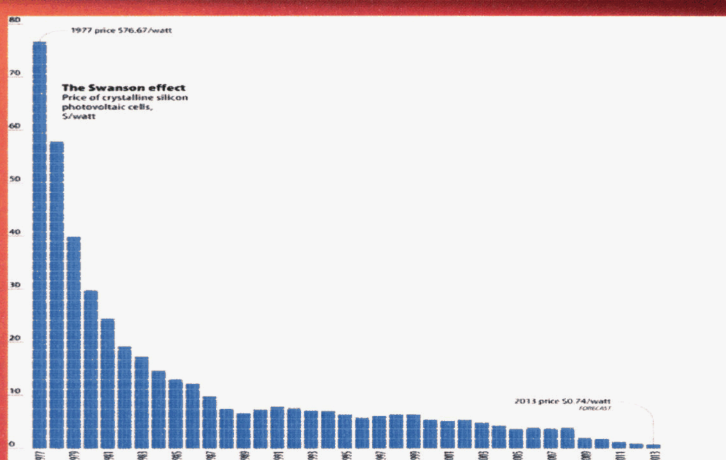
5





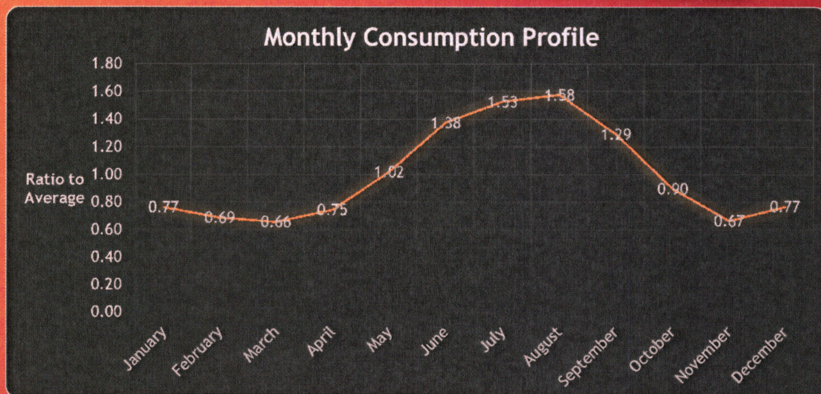
What Happened with Solar?

6



Assumptions

7



Home is 25% more efficient regarding peak demand usage than a standard new-build EE home

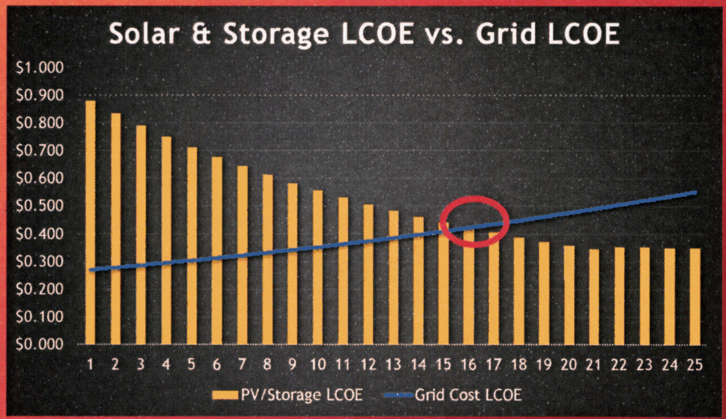
Scenario A

8

- New 100 home community with centralized storage and rooftop solar
  - 100% off the grid
  - 2,000 Square ft. home
- ~$6,000 per home in costs to setup microgrid.
- $.44 kWh rate vs. $.19 kWh from grid
- $111,000 per home

Timeline for cost competitiveness

9



Scenario B

10

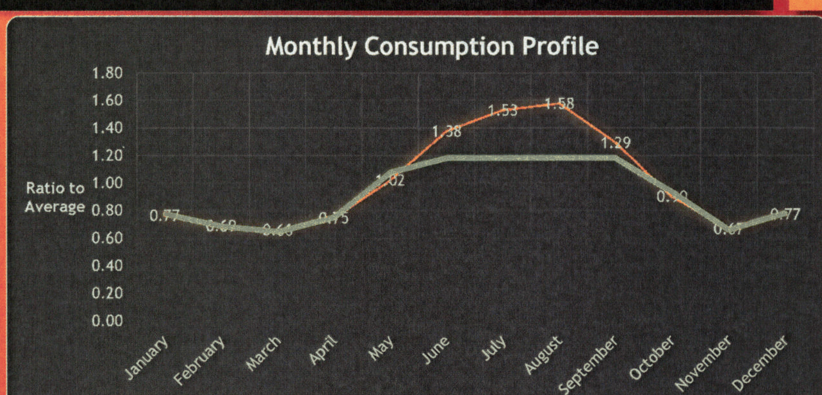
- New 100 home community with centralized storage and rooftop solar with natural gas backup
- ~$6,000 per home to setup microgrid
- 600 kW NG genset at $1,350 per kW (0.098 kWh in peaking mode)
  - $8,100 per home plus an average of $211 per year in fuel and O&M
  - 3% yearly inflation rate on fuel and O&M
- $.24 kWh rate vs. $.19 kWh from grid
- Operates over four months – 11.5% of time for a 30% peak reduction
- $60,000 per home

Natural Gas Backup

11

Natural Gas Load Profile

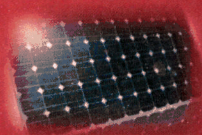
12



Scenario C

13

- New 100 home community with centralized storage and rooftop solar that is connected to the grid
- ~$6,000 per home in hardware costs to setup microgrid plus $6,500 for grid connection equipment
- $.23 kWh rate vs. $.19 kWh from grid
- Four months – 11.5% of time
- $58,000 per home



Scenario D

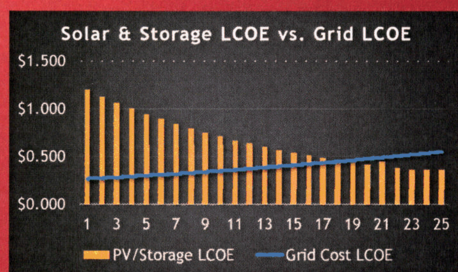
14

- New 100 home community with centralized storage, rooftop solar, and geothermal
- Three ton unit that saves 39% of energy use and takes average demand down 40%
    - $24,000 minus the cost of normal AC unit
- ~$6,000 per home in hardware costs to setup microgrid
- $.30 kWh rate vs. $.19 kWh from grid
- $46,000 per home

Scenario E

15

- One new home in an existing neighborhood with local storage and rooftop solar
- No hardware costs to setup microgrid, but higher battery costs ($750 kWh vs $600 kWh)
- Increased battery size from 119 kWh to 149 kWh
- $.61 kWh rate vs. $.19 kWh from grid and $.44 from community setup
- $151,000 per home



Time Value of Money

16

	A - Solar and Storage	B - Natural Gas	C - Microgrid	D - Geothermal	E - Off the Grid Single Home
Total Cost	$111,000	$60,000	$58,000	$46,000	$151,000
Simple Average/ kWh Cost	$.44 kWh	$.24 kWh	$.23 kWh	$.30 kWh	$.61 kWh
Total Cost/ TVM	$220,000	$123,000	$114,000	$94,000	$300,000
Total kWh Cost/TVM	$.88 kWh	$.49 kWh	$.46 kWh	$.62 kWh	$1.20 kWh
Grid Cost	$68,000/$.27 kWh				

Impact of Assumptions on LCOE

17

Base Case – 16 years to grid parity*

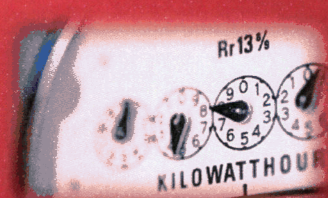
- Half the anticipated storage cost declines – 22 years
- Higher opportunity cost (3% to 5%) – 19 years
- 20% increase in peak – 18 years
- Three days of autonomy – 20 years

*Grid parity does not necessarily correspond to adoption

Key Findings

18

- Must consider in-rush current/start-up current
- Codes and standards
- It is all about the peak and managing risk
- Need EE and energy management
- Geothermal should be more seriously considered



Concluding Observations

19

- Time is all one needs when you have two compounding trends
- Commercial entities using natural gas, solar, and storage may happen sooner than residential
  - 10 year – 2024 timeframe
  - CHP can be used to reduce peak and provide backup
- Exercises like this one can help us obtain the value and proper pricing of grid services

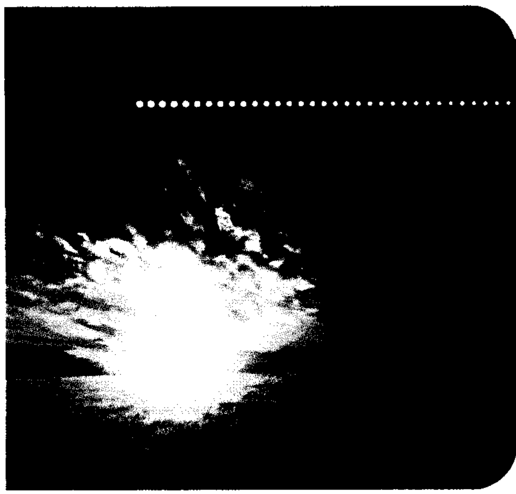
Thank You

20

- APS (for distribution/wires information)
- Southwest Gas (for genset and fuel numbers)
- Green Earth Energy (for geothermal assumptions)
- AES Energy Storage (for guidance on storage characteristics)

Agenda – August 18, 2014

- Elster Overview
- SmartGrid Industry Trends
- Arizona AMI Update
- Elster's SmartGrid Value Proposition



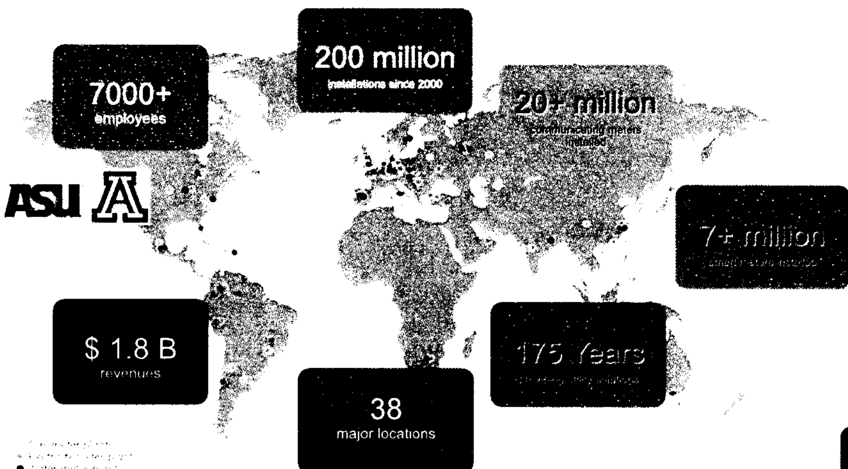
Elster Overview

Global Leadership

Global leadership positions across all Smart Grid segments and end-markets (residential, C&I and T&D)

NORTH AMERICAN AMI	GAS	WATER	ELECTRICITY
#1	#1	#2	#3
in number of AMI systems deployed	global market share	global market share	global market share

Trusted, Strong and Global



175+ years of experience

- American Meter Company (AMCO) founded in New York 1836
- Elster Meters founded in Berlin 1848
- G. Kromschroeder AG established in Osnabrueck 1865
- Kent Water Meters founded in London 1885
- Westinghouse Electric Company founded in Pittsburgh, PA 1894
- Canadian Meter Company 1900
- Westinghouse Electricity Metering Division moved to Raleigh, NC 1953
- Elster Gas Metering acquired by Ruhrgas 1985
- AMCO acquired by Ruhrgas 1988
- Westinghouse Electricity Metering Division acquired by ABB 1990
- GEC Metering acquired by ABB 1997
- Instromet acquired by Ruhrgas 2001
- ABB Electric and Water Metering acquired by Ruhrgas to create Ruhrgas Industries 2002
- Ruhrgas acquired by E.On 2003
- Ruhrgas Industries acquired by funds advised by CVC Capital Partners Formation of Elster Group 2005
- Elster Group acquires Coronis Systems 2007
- Elster Group acquires EnergyICT 2009
- Elster Group IPO (NYSE) 2010
- Elster Group acquired gas-chromatography assets of SLS Micro Technology 2011
- Elster Group acquired by Melrose plc 2012

ELT NYSE

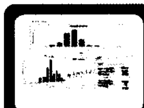
Melrose

Multi-Purpose End to End Solution's Company

elster
Vital Connections

Hardware Products
- **Flexible software defined radio**
- **Standards based**
- **Highest quality**

Software Products
- Innovative User Experience (UX)
- Modular design for flexibility
- Standard and flexible interfaces



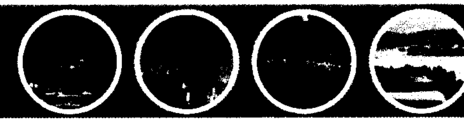
Solutions Portfolio
- Integration, customization and professional support services
- Best-of-breed integrated value partners
- Innovative business models

Focus and commitment on solving customer needs

Proven Technology Delivers a Reliable and Resilient network for All Consumers

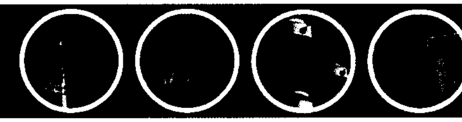
elster
Vital Connections

In Every Environment



From Rural to High Density

Across Multiple Devices



Elster

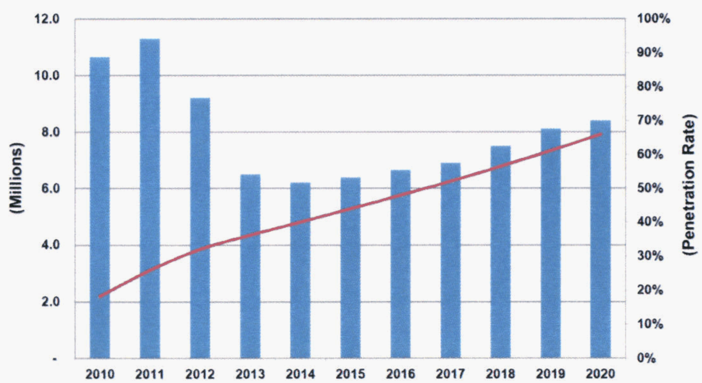
- Robust portfolio of end-to-end solutions
- Significant smart grid communications experience
- Extensive metering portfolio and experience
- Manufacturing flexibility and capability
- Financial strength and global presence
- Strong history of innovation for 175+ years
- First to market with Advanced Metering Mesh Network

SmartGrid Industry Trends

Growth, Sophistication and Intelligence

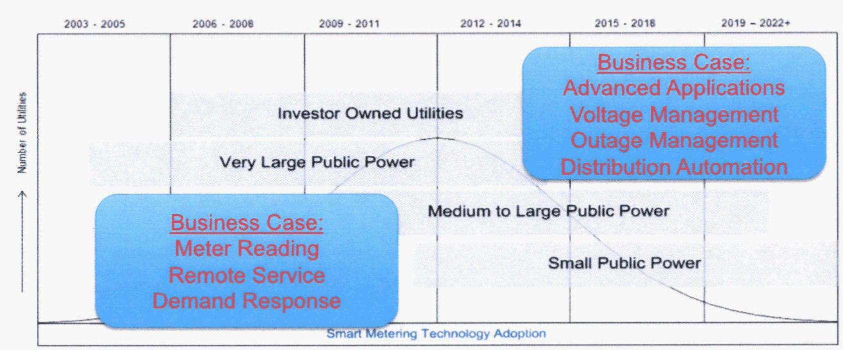
Smart Meter Penetration… 70% by 2020

Chart 6.5 ***Smart Meter Unit Shipments and Installed Base Penetration, United States: 2010-2020***



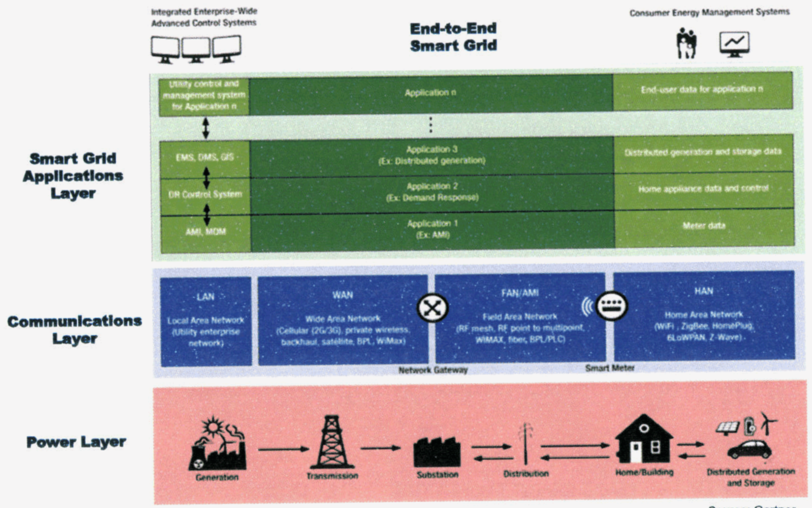
(Source: Pike Research)

AMI Networks: A Mature Technology



Source: Elster tracking study of AMI market penetration; US Dept. of Energy

Driving Value from within the Business

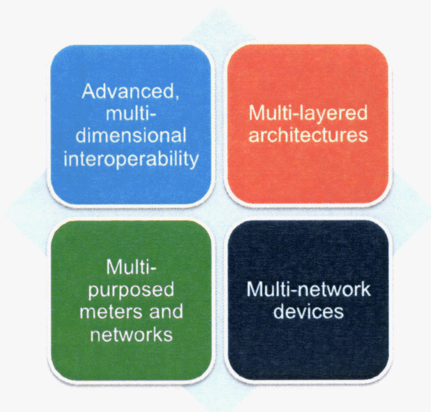


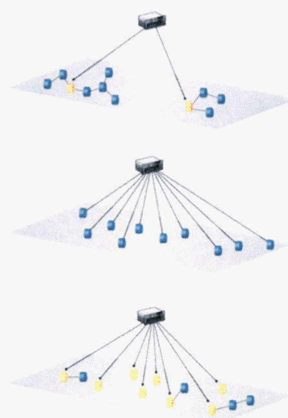
Source: Gartner

Smart Grid Solution Portfolio

Comprehensive, Modular, Universal Architecture

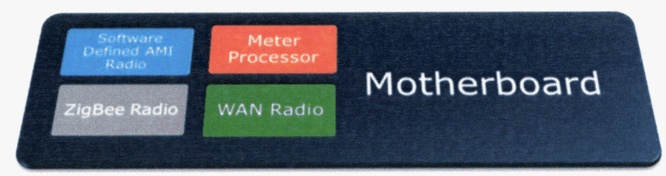
Metering and Communications Evolution





Trends in Metering

- Device & Communications
  - Communications evolution
    - Technology combinations
    - Tighter integration of metrology and communications
    - Standardization
    - Software programmable radios



The Data Deluge Arrives

- Loads of data
- Everywhere
- All the time

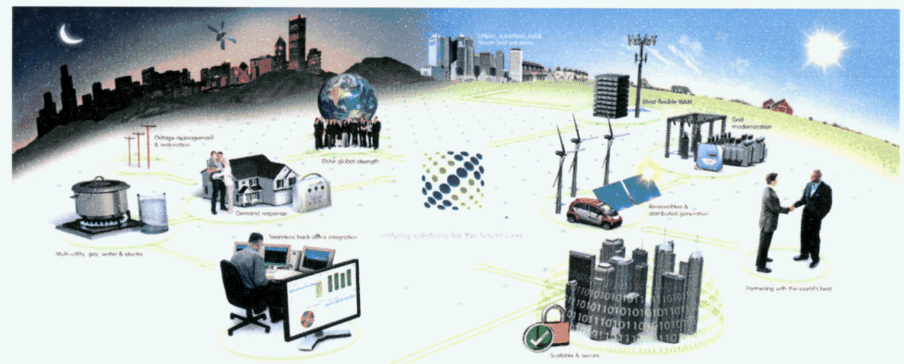
Data – Pervasive metering and sensors of many types convert real world events into data

Information – Massive amount of raw data is collected, verified, organized, and formatted

Intelligence – Information from various sources correlated and analyzed (in various places)

Decisions – Intelligence is used to drive business decisions and take action.

SmartGrid Applications Enabling Superior Customer Experiences



- Outage & restoration management
- Voltage management and conservation
- Demand management
- Consumer pre-pay
- Smart City applications
- Distribution grid monitoring and control

Arizona Ames Update

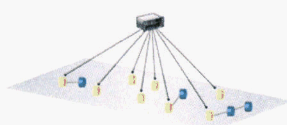
SmartGrid Leadership

A Leader in Smart Meter Deployment

- August 2003 - First Elster Smart Meter Shipped to AZ
- August 2014 - Over 2,000,000 Smart Meters deployed
- 2003 Core AMI drivers:
  - On-Demand Reads
  - Remote Service Connects
  - Improved Billing Accuracy
  - Demand Response
- 2014 Core AMI drivers
  - Voltage Management
  - Distributed Generation
  - Outage and Restoration Reporting
  - Distribution Automation

The AMI Promise is Being Realized

- Over the Air Upgrade Enables
  - Flexible Customer Programs
  - Instrumentation Configuration
  - C&I Temperature Monitoring
  - Service Restoration Confirmation
  - Instrumentation Reconfiguration
    - Voltage Monitoring
    - Alternative Energy Management
  - Enhanced Service Quality
  - Time of Use Rates Have Become More Common Because of Arizona



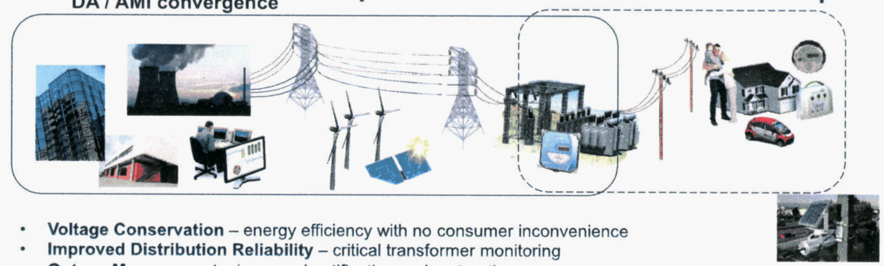
Arizona's Grid Modernization…

Grid Modernization

Integrated Communications Technologies
Integrated Sensing, Monitoring, & Measurement Equipment

Automation at multiple levels

DA / AMI convergence



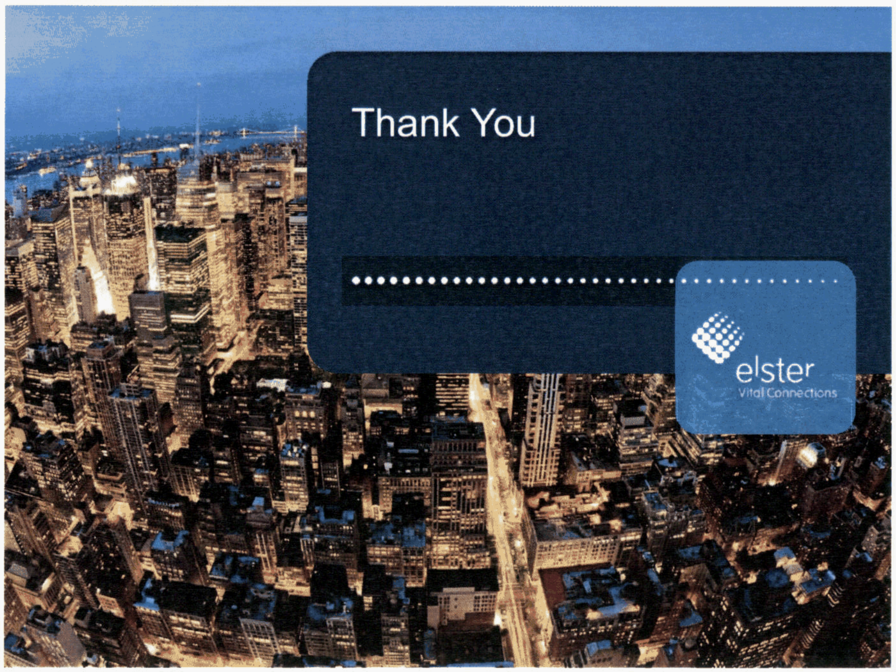
- **Voltage Conservation** – energy efficiency with no consumer inconvenience
- **Improved Distribution Reliability** – critical transformer monitoring
- **Outage Management** – improved notification and restoration
- **Asset Management** – improved lifecycle management of distribution assets
- **Improved Customer Service** – remote disconnects, on demand reads, prepay, etc.

Digital Connectivity to Consumers

- Awareness
- Two-Way
- Relationships

Elster's Solution

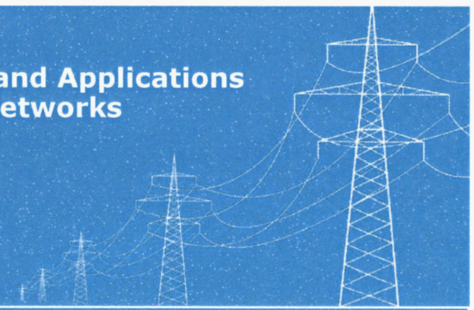
George.Lucas@elster.com


Thank You
elster
Vital Connections

DNV·GL

Emerging Technologies and Applications for Power Distribution Networks

A Brief Update



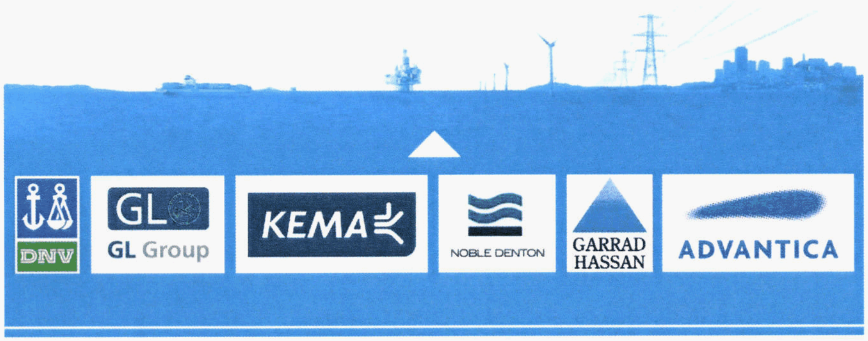
August 2014

Points to cover today

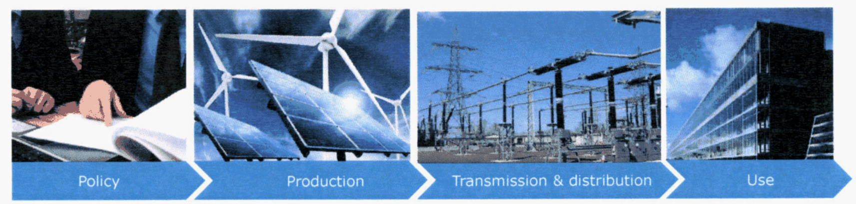
- Who is DNV GL?
- Industry pulse survey results
- Distributed Energy Resources (DER) applications
- Energy storage technologies and developments
- Power Transmission & Distribution automation applications
- Utility analytics and grid optimization applications
- What does it all mean for the electric customer?

Industry consolidation

DNV·GL

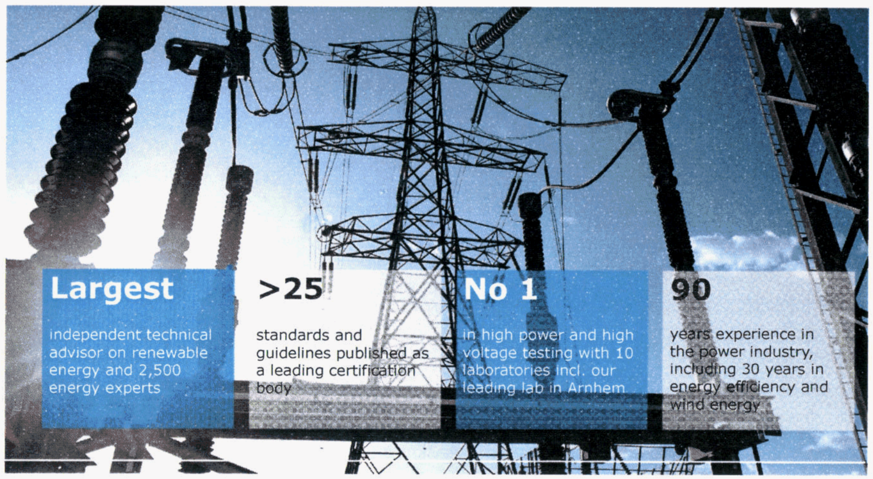


Global service portfolio



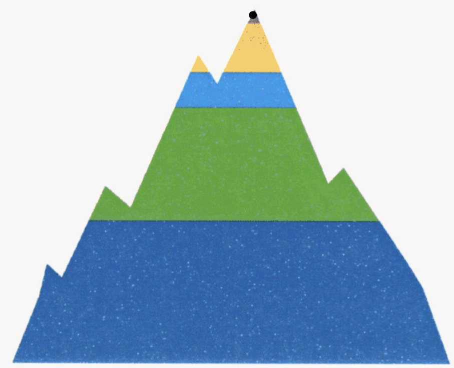
- Power testing, inspections and certification
- Renewables advisory services
- Renewables certification
- Electricity transmission and distribution
- Smart grids and smart cities
- Energy market and policy design
- Energy management and operations services
- Energy efficiency services
- Software

An energy technology powerhouse



What is the most significant challenge facing the utility industry over the next 5 years?

Distributed generation is viewed as a game changer.



Need for asset investment 2%

Need for new business models 2%

Decreased levels of regulatory acceptance of smart grid investments 6%

Other 8%

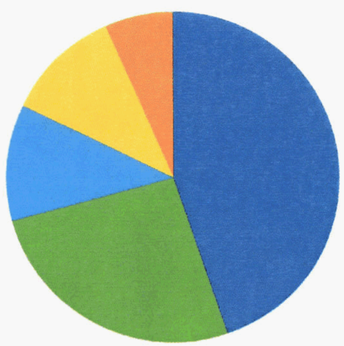
Increased threats for grid and power infrastructure security 10%

Lack of clarity in national energy and environmental policies 32%

Increased interconnection of distributed generation 40%

What approach is your utility pursuing with respect to behind-the-meter applications for end-users?

Demand response is a strong pursuit for entities engaging in behind-the-meter offerings.



Employing DR 45%

Increasing penetration of behind-the-meter DER 26%

Natural-gas fired local generation 11%

Other 11%

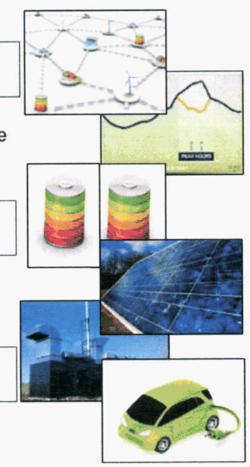
Incorporating EV 7%

Why are distributed energy resources viewed as a growing concern to utilities?

DER technology options reflect both supply and demand-side applications, which have varying degrees of forecasting complexity

Relative Forecasting Complexity

- **SOC – Self Optimizing Customers/ Microgrids**
- **DR – Demand Response (Including Autonomous Price Responsive Load (Dynamic Pricing)**
- **DES – Distributed Energy Storage**
- **DG – (PV – Distributed and "Behind-the-meter" PhotoVoltaics; CHP – Combined Heat and Power)**
- **PEV – Plug-in Electric Vehicles**



DER impacts to electric distribution grids can be substantial and would require careful analysis and consideration

Summary of Forecasted Impacts to Electricity T&D System, 2020[1]

	Impact Category	Area of Impact	Affected Device(s)	% Devices Affected	Key Technology Drivers	Mitigation Tools
Loading Impacts	Peak Load	Secondaries on 13kV feeders	25kVA and 50kVA transformers	20-25%	EV, Fuel Switch to Heat Pump	DR, EE, Storage (EU and CES), Fuel Switch (E to G Water Heaters), Smart Charging
	Evening Load	No major impact at feeder level, expected on secondaries at the 25kVA and 50kVA transformers	TBD	<1%	EV, Fuel Switch to Heat Pump, peak-shifting DR	DR, EE, Storage (if TOU), Fuel Switch (E to G Water Heaters), Smart Charging
	Cold Load Pickup	Feeder level	4kV and 13kV feeders	5-10%	PV, EV, Fuel Switch to Heat Pump	DR, Storage, Fuel Switch (E to G Water Heater), Smart Charging, Advanced DA
Power Quality	Voltage Fluctuation	Feeder level	4kV and 13kV feeders	40-50%	DG PV and DG Wind	Energy Storage, Advanced DA for Renewable Energy Solutions (future)
	Harmonics[1]	Feeder level	dispersed, concentration	All feeders will see some effects; threshold is the issue	Inverter-based applications (EV, DG)	Filters; Power Quality Standards; Storage
Reliability	Short Circuit Duty	Feeder level	4kV and 13kV feeders	45-50%	DG PV and DG Wind, Energy Storage	Advanced protection with dynamic settings, new DG disconnect standards

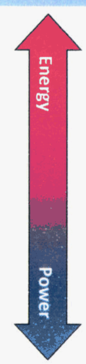
Based on forecasts of smart energy technologies, DNV GL would expect 20 to 30% of 25 kVA transformers on 13 kV feeders for this utility could reach maximum design loading and short-circuit capacity by 2020.

Source: DNV GL client research and analysis

Note 1: U.S. coastal utility serving a major metro area

There are numerous technology options for energy storage, driven by the specific need and application

Technologies range from providing power (<1 hour) to providing energy applications (>1 hour)

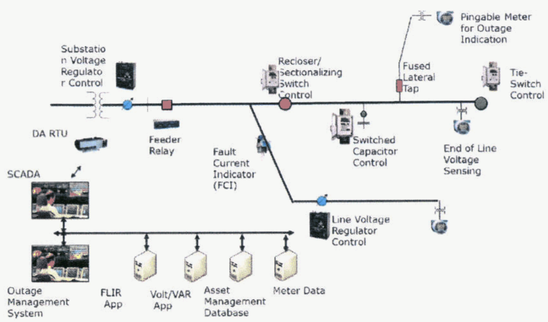


- **Compressed Air Energy Storage** – Will be utilized for "centralized" applications
- **Above Ground CAES** – Gen II, projected as 5 MW, above ground
- **Sodium Sulfur (NaS) batteries** – Long duration, transmission back-up, but expensive
- **Vanadium Redox batteries** – Long duration, flow battery, back-up applications
- **Advanced Lead Acid batteries** – 1 to 4 hours, used for renewables integration support
- **Sodium Nickel Chloride batteries** – Targeting electric vehicles and small-scale backup (e.g., telecommunications systems)
- **Lithium-ion, High Energy** – Used for renewables integration support, perhaps frequency regulation services
- **Lithium-ion, High Power** – Used for frequency regulation, renewables integration support
- **Flywheels** – 15 minute duration, many cycles, used for frequency regulation

In 2013, we observe a market shift in developing applications that include longer duration requirements to serve utility needs (e.g., peak demand reduction), along with companies seeking to introduce new chemistries in battery technology.

Distribution Automation presents significant benefits for grid modernization

Representative DA Technologies/ Applications

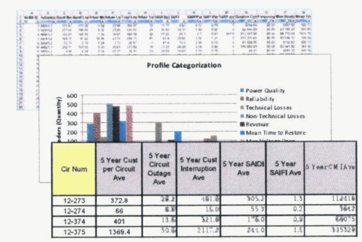


DA Benefit Category	Description
Conservation Voltage Reduction (CVR)	Voltage reduction scheme designed to reduce power demand and energy consumption, within allowable limits (e.g., ANSI C84.1)
VAR Management	Capacitor placement and control for substation peak demand and feeder loss reduction
Outage Restoration	Use of feeder fault current indicators, reclosers, and automated switches to quickly locate and isolate faults
Asset Management *(supported by Substation Automation)*	Use of substation and device measurements to improve planning for capital expenditures. Equipment condition monitoring to support maintenance activities

- Volt/VAR Optimization and Voltage Conservation Reduction (CVR) has evolved significantly in recent years and are continuing to improve (typical system energy reduction of 0.5% to 4%; 80-90% accrues on customer side)
- CVR is viewed as another means to help meet energy efficiency targets and potentially support integration of distributed energy resources (DER) in the longer term
- However, practical approaches to measuring and verifying savings are still evolving

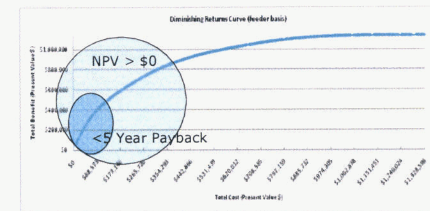
Application of DA technologies does require sophisticated analysis tools for utilities to optimize their investment choices

Key Considerations



- Data sources will typically include:
  - GIS
  - Distribution planning database
  - OMS reliability numbers
  - SCADA or spot measurement circuit peaks
  - Substation transformer loading analysis
- Time-varying factors for technology acceptance and growth projections
- Customer load shapes and demographics

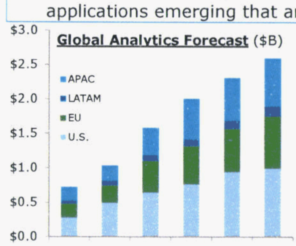
Investment Optimization

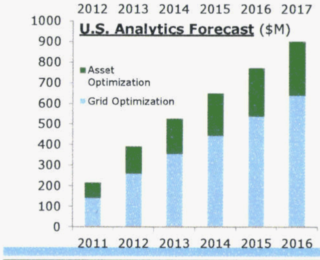


We have found that a majority of Distribution Automation benefits can be achieved with a minority of circuits being automated

Combining AMI interval data and other distribution automation asynchronous data, utility analytics are expected to expand

While much of the "big data" forecasts are based on some degree of hype, there are select applications emerging that are adding tangible benefits to grid automation investments





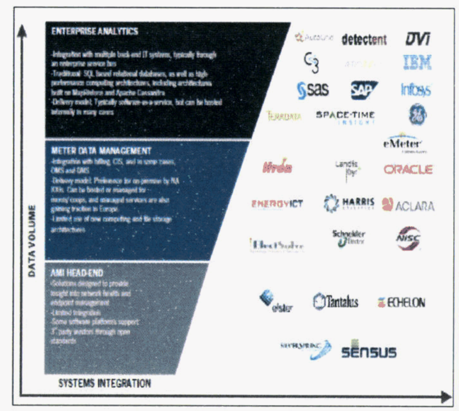
Predominant functions/ benefits

- Alerting utilities to overloads or imminent equipment failure
- Alerting consumers to outages and estimated restoration times via electronic messaging
- Notifying consumers of outage restoration
- Optimizing maintenance activities
- Optimizing asset replacement investments
- Improving reliability to end consumers
- Optimizing the system in near real-time to reduce losses, improve asset utilization, and assure voltage control at customer locations
- Improving capabilities in segmenting the consumer base for demand response (DR) and energy efficiency program implementation

Enabling many of these operational benefits will require greater IT/OT system and process changes than the base AMI systems being installed today

Source: Utility Analytics; GTM Research; DNV GL analysis

Data analytics firms and offerings are growing, in fragmented fashion – market consolidation is likely in the near-term

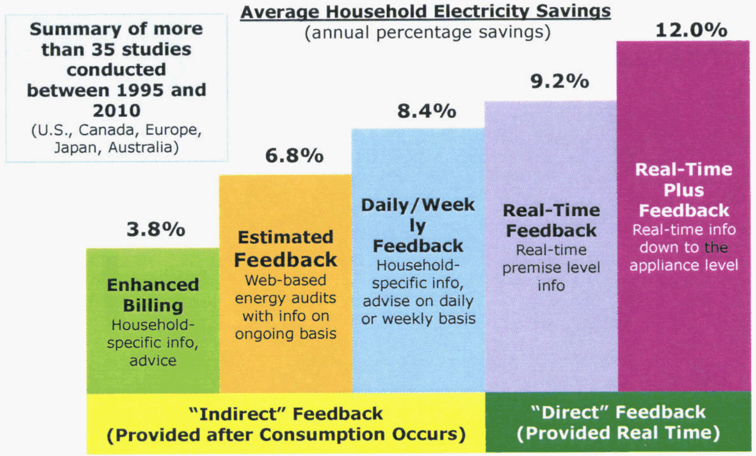


Major Analytics Firms

- **ABB/Ventyx:** focused on predictive analytics solutions via licensed or SaaS offering
- **DataRaker (Oracle):** Combines customer AMI data with GIS, SCADA, OMS, and DMS to improve load and outage awareness
- **eMeter (Siemens):** Offers EnergyIP platform and analytics applications for advanced graphical reporting and visualization
- **GE Energy:** Developing platforms based on CIM standards with visualization and situational awareness
- **Itron:** Offers analytics to enable energy diversion analytics, PQ analytics, and transformer load assessment
- **Silver Spring Networks:** Offers a Smart Energy platform that serves as grid analytics foundation; that also includes DA application

Source: GTM Research; DNV GL analysis

Given these advances in grid modernization and analytics, what does it mean for the electric consumer who chooses to participate?



Source: Advanced Metering Initiatives and Residential Feedback Programs, ACEEE, June 2010.

Thank you for your interest.

Rob Wilhite
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SAFER, SMARTER, GREENER

Broad Smart Grid Benefits Have Been Achieved in a Number of U.S. Deployments, as Reported Individually

Benefit Category	Smart Grid Application/ Benefits Projected or Achieved
Overall energy consumption reduction	• Demonstrated reduction of 1-2% due to distribution automation volt/VAR control (Oklahoma Gas and Electric) • Demonstrated reduction of 16.9% through SmartRate program (Pacific Gas and Electric) • Demonstrated reduction of 20% through energy efficiency programs (Pacific Gas and Electric) • Demonstrated reduction of 9% through demand response program (Oklahoma Gas and Electric) • Reduction of 20% by 2016 through SmartBuilding program (Duke Energy) • Reduction of 18% by providing customers with real-time energy information (Federal Energy Regulatory Commission)
Energy efficiency savings	• Demonstrated savings of 2,060 GWh, 357 MW, and 16.8 million Therms through energy efficiency programs (Pacific Gas and Electric) • Projected savings of 6,000 MWh/yr (Burbank Water and Power)

Sources: GridWise Alliance,, *Realizing the Value of an Optimized Electric Grid*, 2011; Electric Light & Power magazine; Company websites and regulatory filings; DNV GL research and client analysis

Broad Smart Grid Benefits Have Been Achieved in a Number of U.S. Deployments, as Reported Individually (continued)

Benefit Category	Smart Grid Application/ Benefits Projected or Achieved
Reliability improvements	• Projected improvements of 13% in SAIFI, 19% in SAIDI, 7% in CAIDI (Pepco Holdings Inc.) • Projected reduction of 100,000-175,000 (out of 850,000) customer minute interruptions (Commonwealth Edison) • Demonstrated SAIDI reduction of 30 minutes with feeder automation (PG&E) • Demonstrated SAIDI reduction of 25 minutes due to use of adaptive relay schemes (FirstEnergy, NJ) • Demonstrated reduction of SAIDI by 30% with automation of 200 distribution circuits (DMS, GIS, Volt/VAR Control, AMI) – Oklahoma Gas & Electric • Demonstrated CAIDI reduction from 150 to 92 minutes via automated 34kV switches (KCP&L, Missouri)
Outage response time reductions	• Demonstrated reduction of 33 min (47%) to average Customer Minutes of Interruption (CMI) and 18,950 minute reduction of total CMI per circuit from distribution automation (Southern California Edison) • Reduction of $50K/yr loss (Burbank Water and Power) • Estimation of $1,600 to $4,700/ MWh loss for residential and $7,000 to $50,000/MWh loss for C&I (Pepco Holdings Inc.) • Projected reduction in outage response time of 20% due to distribution automation (Duke Energy, Indiana)

Sources: GridWise Alliance,, *Realizing the Value of an Optimized Electric Grid*, 2011; Electric Light & Power magazine; Company websites and regulatory filings; DNV GL research and client analysis

Broad Smart Grid Benefits Have Been Achieved in a Number of U.S. Deployments, as Reported Individually (continued)

Benefit Category	Smart Grid Application/ Benefits Projected or Achieved
Peak demand reductions (via increased DSM programs, Conservation Voltage Reduction (CVR) or Volt/VAR control)	• Demonstrated reduction of 2.5% peak demand using CVR – Snohomish PUD, Washington State • Demonstrated reduction of 200 MW via CVR and Transmission Line Loss Reduction (Georgia Power) • Demonstrated reduction in system peak demand by 75 MW (2% voltage red.= 1-2% peak demand reduction) • Demonstrated reductions of peak demand by 0.7 KW per 1% voltage reduction (AEP) • Projected reduction of 5% peak load (Burbank Water and Power) • Projected reduction of 1.2% to 3.6% through demand side management programs (Pepco Holdings Inc.) • Projected reduction of 6-20% critical peak load in PHI service area (Pepco Holdings Inc.)
Reduce Operations and Maintenance (O&M) costs	• Demonstrated avoided 582 utility service calls at Delmarva Power after Hurricane Irene (Pepco Holdings Inc.) • Projected savings of $74M over 15 yr net present value (Pepco Holdings Inc.) • Projected savings of $4M due to automation (Oklahoma Gas and Electric) • Demonstrated savings of >33M miles driven due to advanced metering infrastructure following major hurricanes (Southern Company, USA)

Sources: GridWise Alliance,, *Realizing the Value of an Optimized Electric Grid*, 2011; Electric Light & Power magazine; Company websites and regulatory filings; DNV GL research and client analysis

Broad Smart Grid Benefits Have Been Achieved in a Number of U.S. Deployments, as Reported Individually (continued)

Benefit Category	Smart Grid Application/ Benefits Projected or Achieved
Green house gas (GHG) reductions	• Projected 29% reduction in 10 years (NV Energy) • Projected 0.7-5.4 million tons reduction 2011-2020 (SDG&E) • Projected reduction of 1 million tons CO_2 and 215 tons of NO_2 (Pacific Gas and Electric) • Projected reduction of 220,000 tons of green house gases through SmartBuilding program (Duke Energy)

The U.S. Department of Energy has provided further insight into the impacts of the $7.9B ($3.4B federal funds) in smart grid investment grant projects:

- 99 total smart grid programs funded
- 15.5 million smart meters to be deployed ($4.5B, 65% complete)
- 6,500 circuits to be automated ($2.5B, 40% complete)
- 826 networked phasor measurement units installed ($1B, 20% complete)

Sources: GridWise Alliance,, *Realizing the Value of an Optimized Electric Grid*, 2011; Electric Light & Power magazine; Company websites and regulatory filings; DNV GL research and client analysis

Limited-Income Customer EZ-3 Recruitment Pilot

Aaron Dock
Manager of Load Research

ACC Workshop on Emerging Technologies
August 18th, 2014

What have we learned?

- Limited income customers can save money by correctly implementing the SRP EZ-3 price plan.
- Pairing a programmable thermostat with proper implementation of the EZ-3 price plan even further reduced a customer bill and SRP peak demand.
- Most usage shifting and bill savings occurs during the summer months.

EZ-3 Price Plan

- Prices are higher from 3:00 pm to 6:00 pm weekdays, and lower than E-23 during all other hours, including weekends.
- Customers with 8-to-5 work schedules get home near the end of or after the more expensive on-peak period.
- Gives customers another time-of-day option to take control of their bills and may be a better match with their lifestyles.
- Pre-cooling is much more effective.

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Eligible Participants…

- have a household income not exceeding 200% of federal poverty guidelines.
- are single-account customers with (at minimum) 12 months of E-23 billing history.
- are borderline savers with respect to E-23 vs. E-21.
- reside in a single family dwelling with one central air conditioner.
- do not own a programmable thermostat.
- are not seasonal customers.

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Limited-Income (LI) Customer EZ-3 Pilot

Test impact of programmable thermostats

- Recruited customers identified as likely savers on EZ-3 vs. Basic Price Plan
- SRP installed pre-programmed thermostats for EZ-3 plan

	Programmable Thermostat	No Programmable Thermostat
June 2013 *(start)*	116	180
May 2014 *(end)*	94	154
Net change	(22)	(26)

Why Customers Left Pilot		
Basic plan	10	11
Turned off service	9	6
Other EZ-3 / TOU plan	1	2
M-Power	1	3
Other	1	4

EZ-3 Pilot Results: Average Annual Bill Savings

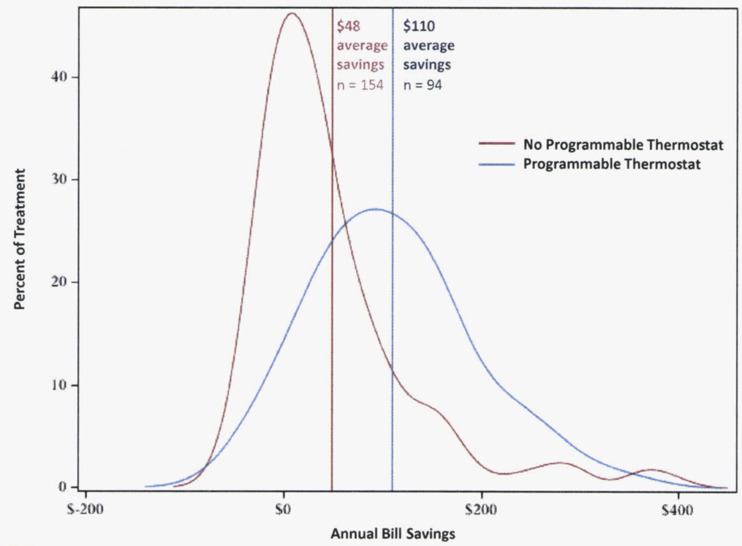
June 2013 – May 2014

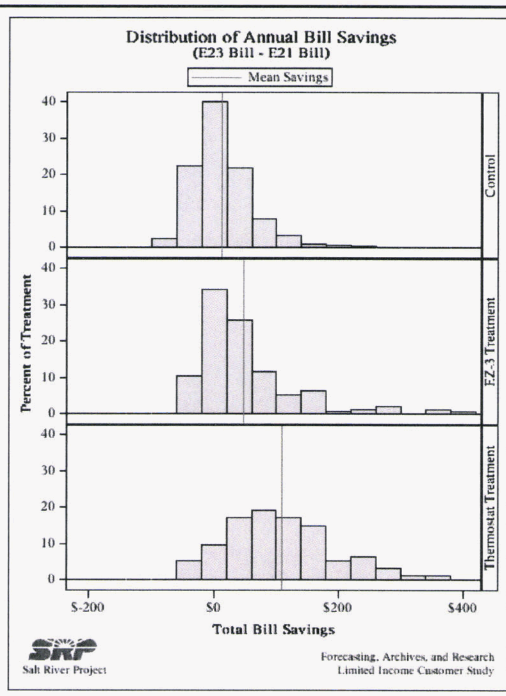
	Programmable Thermostat	No Programmable Thermostat
Basic Plan Bill	$1,531	$1,631
EZ-3 Bill	$1,421	$1,583
Savings on EZ-3	**$ 110**	**$ 48**
Percent Savings	7.2%	2.9%

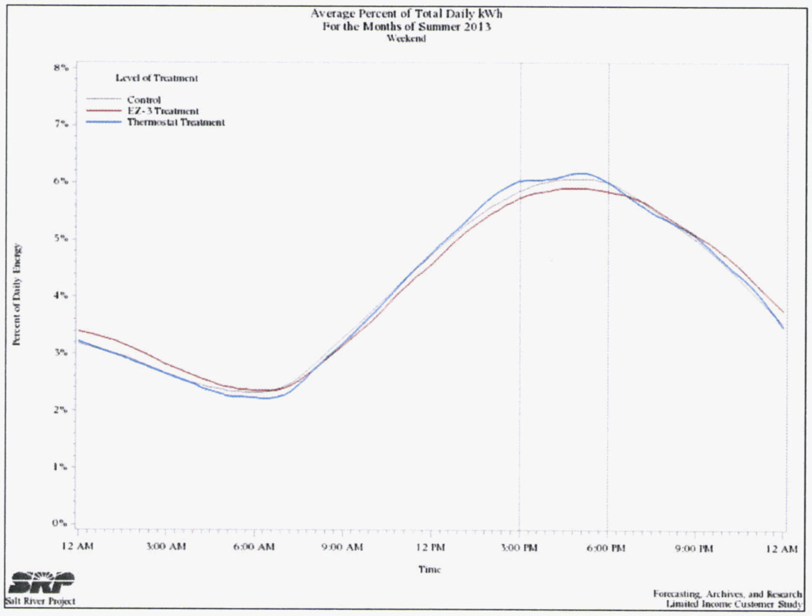
- Most participants saved annually, with about 90% or more of the savings occurring in the summer months of May – October
- Customers saved by shifting energy use, not conserving energy

EZ-3 Pilot: Distribution of Annual Bill Savings

June 2013 – May 2014






Average Percent of Total Daily kWh
For the Months of Summer 2013
Weekend
Level of Treatment
Control
EZ-3 Treatment
Thermostat Treatment
Percent of Daily Energy
0%
1%
2%
3%
4%
5%
6%
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12 AM
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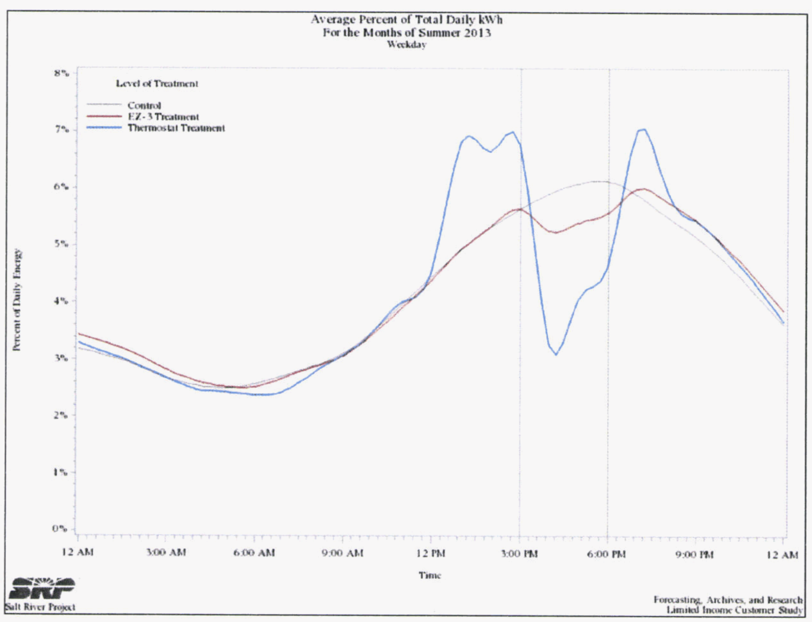
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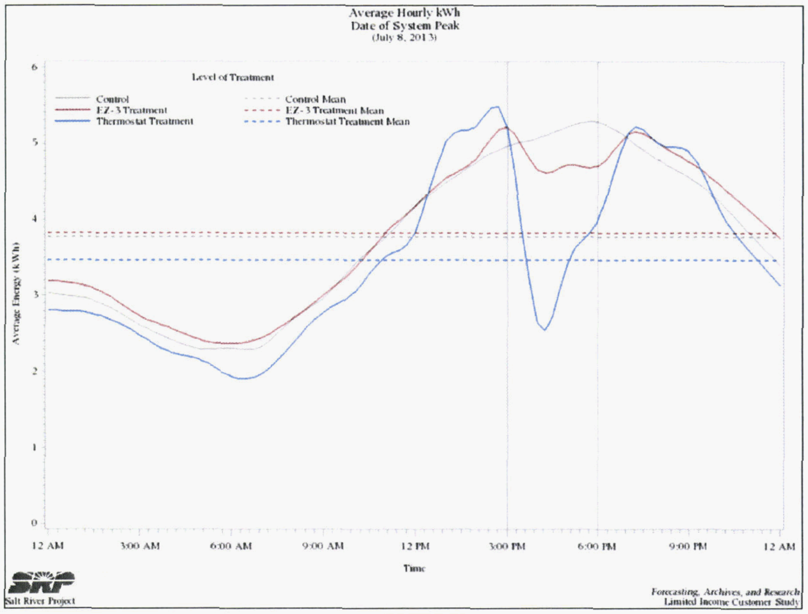

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Conservation

Though conservation was not a goal of this pilot, the energy consumption of EZ-3 recruits was compared to the control group to see if there were measured conservation (or increased consumption).

EZ-3 customers who received a programmable thermostat used slightly less (1.8%) energy than the control group during the summer months. However, results were not statistically significant on a seasonal or annual basis.

Thank you.

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